INDIA - SOUTH-WEST COAST
GAS MARKET STUDY

Prepared for

SHELL INTERNATIONAL GAS LIMITED

Final Report

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August 1996

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GLOSSARY

BCM	Billion Cubic Metres
C&F	Cost and Freight
CEA	Central Electricity Authority
CIL	Coal India Limited
COPE	Crude Oil Process Equalisation
CPCB	Central Pollution Control Board
EIA	Environmental Impact Assessment
EPA	Environment Protection Act
FIPB	Foreign investment Promotion Board
FO	Fuel Oil
FSP	Freight Surcharge Pool
GDP	Gross Domestic Product
GOI	Government of India
GWh	Giga watt hour
IPC	In Principle Clearance
IPP	Independent Power Producer
KEB	Karnataka Electricity Board
KPC	Karnataka Power Corporation
KSEB	Kerala State Electricity Board
kV	Kilovolts
kVA	Kilovolt-ampere
kWh	Kilowatt hour
LHV	Low Heat Value
LNG	Liquefied Natural Gas
MCM	Million Cubic Metre
LOI	Letter of Intent
LPG	Liquefied Petroleum Gas
MGR	Merry-go-round
MINAS	Minimal National Standards
MMT	Million Tons
MoEF	Ministry of Environment and Forests
MOP	Ministry of Power
MVA	Megavolt-ampere
MW	Megawatt
NAAQM	National Ambient Aair Quality Monitoring
NEERI	National Environmental Engineering Research Institute
NLC	Neyveli Lignite Corporation

NOC	No Objection Certificate
NPC	Nuclear Power Corporation
NTPC	National Thermal Power Corporation
OCC	Oil Co-ordination Committee
ONGC	Oil and Natural Gas Commission
PLI	Public Liability Insurance
PPA	Product Price Adjustment / Power purchase agreement
SDP	State Domestic Product
SEB	State Electricity Board
SLF	System Load Factor
SPCB	State Pollution Control Board
T&D	Transmission and Distribution
TCF	Trillion Cubic Feet
TEC	Techno-Economic Clearance
TEL	Tetraethyl Lead
TNEB	Tamil Nadu Electricity Board
TPA	Tons per annum
TPD	Tons per day

TERMS OF REFERENCE

Terms of Reference for India - South West Coast Gas Market Study

Scope

The aim of this "scouting" study is to provide an overview of the potential markets for natural gas in the states of Karnataka, Kerala and Tamil Nadu post 2000, and to recommend a site for an LNG terminal based on market/economic considerations. The study will focus on power generation, but will also take into account other major segments of the market.

The report will have the following structure:

Chapter 1 Energy Demand

For each state, a summary of final energy demand, both existing and projected for 2000, 2005, 2010 and 2015, by market segment and fuel type; and a brief review of current and expected sources of energy supplies and current energy prices.

Chapter 2 Energy Policies and Regulatory Matters

A brief review of the structure of the energy industry and of existing state (and, where applicable; Central Government) energy policies, existing taxes and other relevant regulatory detail. Outline of pollution controls and other relevant environmental issues.

Chapter 3 Power Generation

Existing and projected (through to 2015) electricity demand and supply by fuel type. Projections to be based on two scenarios which take into account the role of Government, the relationship between power generation and politics and the possible effects of the environmental movement (precise assumptions to be agreed). Existing tariff structures and differentials.

The relative competitiveness of gas as a fuel at the burner tip against competition from naphtha and imported and domestic coal.

Description of the local electricity supplies - transmission systems, losses, baseload, load factors, despatch policy, fuel "pass through" clauses in PPA (the extent and manner in which variations in fuel costs are passed onto the power purchaser) etc.

The strengths and weaknesses of the respective state electricity boards (financial, operational etc.)

Chapter 4 Industry, Chemical Feedstock and Other Users

Identification of existing, major, potential gas consumer including industry - sponge iron, fertilizer manufacturers, glass, ceramics, textiles, cement etc. - chemical feedstock, commercial, domestic and automotive. Identify areas of major potential gas consumption.

What are the alternative fuels? How much could the users afford to pay for gas in today's market? (Estimate only, after comparison with other fuel costs if known).

Chapter 5 Demand Conclusions and LNG Terminal Options

Identification of main areas of gas demand and the geographic spread.

Map showing spread of main electricity demand.

Comments as to whether current plans for future projects meets likely demand.

Recommendations for LNG import site/area options.

Summary table of potential LNG requirements.

CHAPTER 1
EXECUTIVE SUMMARY

1.1. POWER SECTOR

Electricity is legislated upon both by the Central, as well as the State governments. The Central Electricity Authority advises the Ministry of Power at the Centre, while at the state level, State Electricity Boards (SEBs) are statutory organisations looking after development of the power sector. Tariffs for purchase of power from private producers as well as for sale to ultimate consumers are set by the state governments in consultation with the SEB. The Central government has the final say in granting clearances for power projects in all cases, as it approves the fuel linkages. In the power sector, environmental issues are mostly related to hydro projects though awareness has started to increase with regard to pollution from coal based thermal power stations.

All the three states suffer from power shortages. Karnataka is the worst affected, having a shortfall of over 3000 GWh in 1993-94. The shortages are expected to disappear in all the states by the year 2000, with the addition of new generating stations. It has been estimated that the installed generating capacity in Karnataka will increase by over 2.7 times the 1995 levels by the year 2015. The growth will mainly be in the coal-fired capacity along with hydro and fuel oil based stations. Generating stations using gas and naphtha are also expected to come up, mainly in 2005-10 and later. In the case of Kerala, the increase in installed capacity will be about 3.5 times, with major additions occurring in the coal, gas and naphtha fuelled plants. Tamil Nadu will witness a 2.4 times growth in installed capacity with major additions occurring in coal, fuel oil and gas based plants. Major additions are planned in gas-fired stations in the periods 2005-10 and 2010-15. As per the current proposals, Karnataka will experience a shortfall of nearly 400 MW in 2015 in the case of the high growth scenario, but the other two states have a comfortable surplus, and could export power to Karnataka.

In all the three states, there exists a high level of cross subsidies in electricity prices across the sectors. Commercial and industrial consumers, particularly medium and large consumers, are charged higher per unit rates compared to the average cost of generation and supply, while electricity for the domestic sector is sold at a subsidised rate. The agriculture sector gets free supply of electricity in Tamil Nadu, and only pays a nominal amount in Karnataka and Kerala.

The average sector-wise tariff in 1995-96 for the three states along with the average cost of supply of power in US ¢/kWh, is given in Table 1.1.

Table 1.1: Average cost of supply and average electricity tariff (1995-96)

(¢/kWh)

State	Domestic	Commercial	Agriculture	Industrial	Average tariff	Cost of supply
Karnataka	3.12	11.80	0.59	6.58	4.07	4.17
Kerala	1.84	4.29	0.63	3.17	2.81	3.33
Tamil Nadu	2.63	6.79	0.00	6.50	4.18	5.09
Note: The conversion rate used is Rs 35.00/US $						

The SEBs are trying to increase the tariff for the agricultural sector and bring it closer to the cost of supply. The Karnataka Electricity Board has taken a step in this direction with their new tariffs announced with effect form July 1, 1996.

1.2. COAL AND HYDROCARBONS

Coal and hydrocarbons are under the control of the Central government. A major portion of the cost of coal to a consumer is the transportation charge from the mines to the consumption centre. The landed cost of domestic coal at Mangalore works out to be about $ 43/ton, as compared to the pit-head price of about $ 9.50/ton.

The major coal demand in these states is in coal-fired generating stations, though cement and iron & steel plants also have a share in the demand for coal.

The demand centres in the three states are located at a distance of more than 2000 km form the coal mines. The major mode of coal transport is rail ways. Movement of coal on the rail routes is becoming difficult due to limitation of line capacity. Indian Railway will also be facing a shortage of rolling stock for movement of coal if sufficient finances are not made available to them.

It has been estimated that only 55% of the coal demand of the power sector in the three states will be met through domestic coal from 2001 onwards.

Oil companies have an assured return on the capital employed due to the current pricing regime. However, the administered pricing regime has started undergoing some change as parallel marketing for kerosene, LPG, LSHS and lubricants has now been allowed.

The rate of growth for all petroleum products is maximum in Karnataka followed by Kerala. The demand for naphtha is expected to be greater than 550 thousand metric tons in all the three states by 2015.

1.3. INDUSTRIES OTHER THAN POWER

There exists significant potential demand for natural gas in the cement, fertiliser and iron & steel industries, mainly for capacities which are expected to come up in the next few years. The existing sales potential in billion cubic metres per year in industries other than power for Karnataka, Kerala and Tamil Nadu has been estimated as 0.884, 0.369 and 1.208 respectively. The total future potential (by 2015) has been estimated to be 5.245, 0.569 and 1.370 billion cubic meters per year in Karnataka, Kerala and Tamil Nadu respectively.

1.4. SALES POTENTIAL FOR NATURAL GAS

The gas requirement for a power plant has been taken as 1.04 million cubic meter (MCM) per year for every megawatt of installed capacity, assuming a plant load factor of 68.5% and the calorific value of gas as 8760 kilo calories/Nm^3.

The lower limit for the gas requirement has been derived from the installed capacities of the power stations committed to using gas.

The upper limit for natural gas requirement has been derived as per the following:

1. Since power stations using gas oil, fuel oil or naphtha can switch to using gas without major modifications, it has been assumed that all power stations using these fuels would switch to gas if it was made available at a competitive price.
2. The Ministry of Coal in its IX Plan Document has estimated that only 55% of the coal requirement of the power sector in South India will be met in the year 2001. It has been assumed that this situation of shortages will continue till 2015. To meet the requirements of the balance (coal based) capacities, options would be either imported coal or gas. The planned coal based capacity amenable to a fuel switch would therefore be about 45% of the additions in the period 2005-15 (considering the lead time required to make LNG available). This would amount to 2655 MW (45% of 5900) of capacity which could use natural gas instead of imported coal.

The lower limit of the sales potential for natural gas is the maximum in Tamil Nadu, reaching over 3500 million cubic meters per year by 2015. The upper limit is again highest in Tamil Nadu at nearly 6000 million cubic meters per year in 2015. The sales potential in the power sector is tabulated in Table 1.2.

Table 1.2: Natural gas sales potential in the power sector

(MCM/year)

	Lower limit	Upper limit
Karnataka		
2000	0	931
2005	42	1282
2010	354	2437
2015	354	2905
Kerala		
2000	0	0
2005	62	158
2010	582	1475
2015	1102	3308
Tamil Nadu		
2000	140	140
2005	484	900
2010	2044	3439
2015	3604	5917
All three states		
2000	140	1071
2005	588	2340
2010	2980	7351
2015	5060	12130

1.5. IMPUTED VALUES FOR NATURAL GAS

Imputed values for gas have been calculated for domestic and imported coal and naphtha. The following broad trends emerge:

1. **Gas vs. domestic coal**: Costs of electricity generation based on domestic coal are around 5 cents/kWh. The imputed values for gas work out to around 5 $/MMBtu, which implies that gas can offer stiff competition to domestic coal. Further, bottlenecks in coal transportation add to the attractiveness of gas fired capacity.
2. **Gas vs. imported coal**: Imputed values for gas work out to between 6-7 $/MMBtu, which are higher than the corresponding values for domestic coal. This is due to the fact that capital costs are assumed to be higher in the case of imported plants due to the FGD units, which are presently not mandatory in India as Indian coal has a low sulphur content.
3. **Gas vs. imported naphtha**: Imputed values for gas work out to between 5.3- 6.5 $/MMBtu in the case of imported naphtha, implying that naphtha could provide

stiff competition to gas. However, oil prices are more likely to increase in the medium term and thus imputed values would be higher.

4. **Gas vs. domestic naphtha**: Imputed values for gas work out to between 5.5-6.5 $/MMBtu in the case of domestic naphtha.

Overall, the imputed value analysis shows that gas fired capacity has considerable potential and the economics is attractive vis-à-vis other fossil fuel options.

1.6. LNG TERMINAL SITING OPTIONS

An integrated examination of the likely large demand centres of the three states was carried out, and on that basis the following possible locations were thought to offer good potential:

1. **Mangalore, Kasargod area**: This would be in close proximity to the demand centres in and around Mangalore (Karnataka) and Kasargod (Kerala). However, inland demand centres, i.e. Bellary, Raichur and Gulberga (590 km from Mangalore) are relatively far away and the economics of laying a pipeline to feed these inland locations would require a detailed techno-economic evaluation. (If found feasible, the line could later be extended into Andhra Pradesh). This line would have to cross the Western Ghats shortly after leaving the coastal plains near Mangalore.

2. **Cochin area**: The demand immediately in and around Cochin is estimated to be considerably lower than the Mangalore /Kasargod region. However, there is a gap between the Western Ghats and the Annamalai Hills which will facilitate laying a gas pipeline from Cochin through the gap at Palghat and onto Coimbatore and Bangalore. Although the projected demand at these two centres is not high, it is interesting to note that when the Hazira-Bijaipur-Jagdishpur (HBJ) pipeline (India's only inter-state gas pipeline) was laid across west and north India, the position of thermal power stations and fertiliser was decided more by the proposed alignment of the pipeline than visa versa. A coastal pipeline linking the Mangalore/Kasargod area to the Cochin area (either way) could also be considered.

3. **Madras/Ennore area**: This area has also been identified as a large demand centre. The Madras Refinery (MRL) of capacity 130,000 b/d receives crude at 2 jetties of the Madras Port Trust with drafts of 14.63 m and 16.15 m. Barring VLCCs, all types of vessels can be handled at these jetties. However, the jetty occupancy is very high at 84% and availability of land in the port area is almost ruled out.

Shell's requirement for an LNG terminal have been noted, i.e. a draft availability of 13.5 m, a 25 hectare site with a buffer zone from other installations of between 400m and 2000m and a distance from residential areas of between 2 - 5 km. This would almost certainly indicate that LNG tanker receipt and terminal facilities cannot be erected at any of the existing ports and a captive LNG jetty would have to be constructed. Generally, drafts on the eastern coast are deeper than on the west coast. To meet a draft of 13.5 m on the west coast round-the-year dredging may be required. Also, it must be remembered that coastal areas, particularly Kerala, are heavily populated and safety distances to the extent indicated may need to be reduced.

CHAPTER 2
ENERGY DEMAND

It has been estimated that the installed generating capacity in Karnataka will increase by over 2.7 times the 1995 levels by the year 2015. The growth will mainly be in the coal-fired capacity along with hydro and fuel oil based stations. Generating stations using gas and naphtha are also expected to come up, mainly in 2005-10 and later. In the case of Kerala, the increase in installed capacity will be about 3.5 times, with major additions occurring in the coal, gas and naphtha fuelled plants. Tamil Nadu will witness a 2.4 times growth in installed capacity with major additions occurring in coal, fuel oil and gas based plants. Major additions are planned in gas-fired stations in the periods 2005-10 and 2010-15. The major coal demand in these states is in coal-fired generating stations, though cement and iron & steel plants also have a share in the demand for coal. The rate of growth for all petroleum products is maximum in Karnataka followed by Kerala. The demand for naphtha is expected to be greater than 550 thousand metric tons in all the three states by 2015.

2.1. INTRODUCTION

Of the three states, Tamil Nadu has the highest total population, while Karnataka is the largest in terms of area covered. The per capita income of Karnataka is the highest at Rs 6313, followed closely by Tamil Nadu at Rs 6205, while Kerala's is Rs 5065. This information is summarised in Table 2.1.

Table 2.1: General comparison of Karnataka, Kerala and Tamil Nadu

	Karnataka	Kerala	Tamil Nadu
Area ('000 sq. km)	192	39	130
1991 Population (millions)	44.98	29.10	55.86
Urban population (percent)	30.9	26.4	34.2
1993 Per capita income (rupees)	6313	5065	6205

2.2. ELECTRICITY

2.2.1. Existing demand

The final consumption of electricity in each state, as on March 31, 1994, disaggregated by market segment is given in Table 2.2. This is the latest data available.

Table 2.2: Final consumption of electricity disaggregated by market segment (1993-94)

(GWh)

	Electricity Sales					
State	**Agriculture**	**Commercial**	**Domestic**	**Industrial**	**Others**	**Total**
Karnataka	6105	375	2271	4971	386	14108
Kerala	261	852	2087	2789	255	6244
Tamil Nadu	5706	1176	3375	9051	1548	20856
Note: 'Others' includes railway traction, public water works, street lighting, etc.						

Source: Public Electricity Statistics, General Review, Central Electricity Authority, 1993-94

As can be seen from the above tables, even though Tamil Nadu's area is less than 70% of Karnataka's, its industrial sector consumes 80% more electrical energy than Karnataka's.

The agricultural consumption in Kerala is relatively low due to the high water table in the state, thus reducing the need for installation of irrigation pump-sets. The low consumption in the agriculture sector accounts for the ratios of domestic, commercial and industrial sectors being high in Kerala relative to the other two states.

The percentage shares of different sectors in each state are shown in Figures 2.1, 2.2 and 2.3.

2.2.2. Projected demand

In the case of the domestic sector, the sector's electricity consumption was taken as the dependent variable, and regressed against the population of the state. Since the growth rate of the State Domestic Product (SDP) does not have an impact on the growth rate of population, and also that the growth rate for population is easier to predict with some certainty than the growth of the SDP, only one scenario for population growth has been used. This translates to one scenario for electricity consumption in the domestic sector.

The electricity requirement projections in the case of the agriculture sector, were done by fitting a regression equation. The gross irrigated area in the state was taken as the independent variable, while the sector's electricity consumption was taken as the dependent variable. Similar to the case of the domestic sector, the rate of growth of electricity consumption in the agriculture sector is not dependent on the rate of growth of the SDP, but on the land area to be irrigated. Therefore only one scenario for electricity consumption in the agriculture sector is presented.

Figure 2.1: Shares of different sectors in total electricity sales in Karnataka (1993-94)

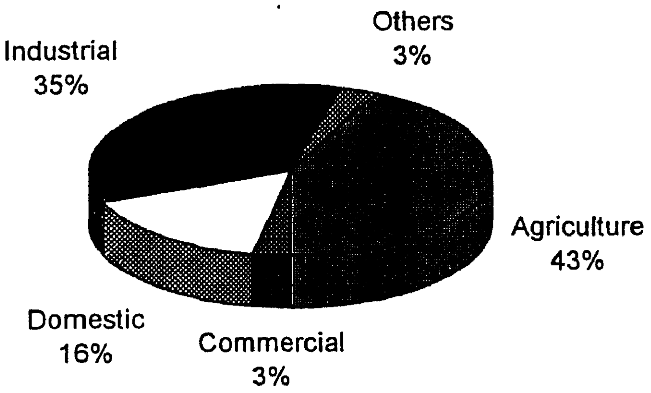


Figure 2.2: Shares of different sectors in total electricity sales in Kerala (1993-94)

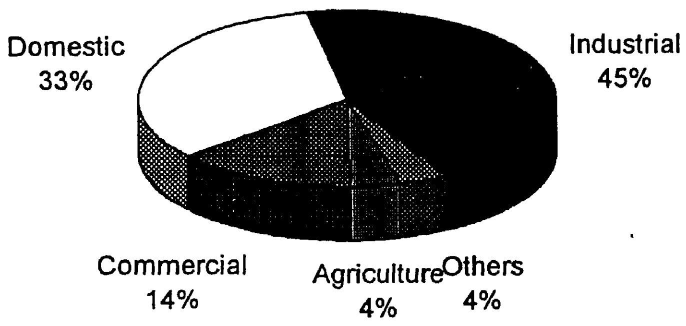
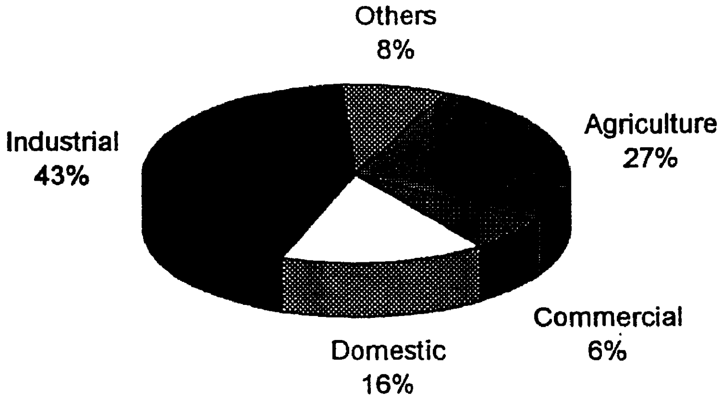


Figure 2.3: Shares of different sectors in total electricity sales in Tamil Nadu (1993-94)



For the industrial and commercial sectors, the projections have been done by fitting a regression equation, taking the sectoral consumption as the dependent variable, and the corresponding sector's contribution to the SDP as the independent variable. Two scenarios were used for the growth of the SDP; growth projections estimated by the Planning Commission were used to obtain the 'high' value, and a restricted growth scenario to obtain the 'low' value. Two scenarios are presented in the case of commerce and industry because these two sectors are the major contributors to the State Domestic Product, and any change in the rate of growth of SDP will have a direct impact on the two sectors.

The high growth scenario uses an overall annual growth rate of approximately eight percent for India's gross domestic product (GDP), and this formed the basis for the forecast of the rate of growth for the SDP. In the case of the low growth scenario, it has been assumed that infrastructural bottlenecks, political instability, environmental activism, etc. will restrict the overall growth rate of the GDP to about six percent per annum.

Tables 2.3 and 2.4 give electricity demand disaggregated by sector for the high and low growth scenarios respectively for the three states.

2.2.2.1. Karnataka

Agriculture sector's consumption of electricity more than doubles over the 15 year period from 2000 while that for the domestic sector grows by just over 1.5 times the 2000 level.

For the high and low growth scenarios respectively, the consumption of electricity in the commercial sector grows to 4 times and 2.75 times the year 2000 levels by the year 2015. In both the cases, the growth far exceeds that for industry, which is at 2.4 and 1.8 times for the high and low growth scenarios respectively. This is to be expected as with the growth of the economy, the services sector gains increasing importance.

It is of interest to note that the growth of the total electricity consumption does not vary much between the high and low growth scenarios, being of the order of 2.2 and 2.0 times respectively of the 2000 levels in year 2015.

ble 2.3: Disaggregated electricity demand projections (high growth)

(GWh)

Year	Agriculture	Commercial	Domestic	Industrial	Others	Total
rnataka						
2000	9313 (7.3%)	479 (4.2%)	2785 (3.5%)	6182 (3.7%)	884	19643 (5.7%)
2005	12588 (6.2%)	738 (9.0%)	3259 (3.2%)	7733 (4.6%)	1146	25463 (5.3%)
2010	16110 (5.1%)	1232 (10.8%)	3762 (2.9%)	10696 (6.7%)	1498	33299 (5.5%)
2015	19822 (4.2%)	1936 (9.4%)	4291 (2.7%)	14907 (6.9%)	1930	42886 (5.2%)
rala						
2000	358 (5.4%)	1260 (6.7%)	2592 (3.7%)	3582 (4.3%)	678	8470 (5.2%)
2005	454 (4.9%)	2069 (10.4%)	1329 (3.8%)	4945 (6.7%)	921	11518 (6.3%)
2010	559 (4.2%)	3614 (11.8%)	3731 (3.6%)	7550 (8.8%)	1344	16798 (7.8%)
2015	670 (3.7%)	5810 (10.0%)	4356 (3.1%)	11252 (8.3%)	1921	24009 (7.4%)
mil Nadu						
2000	6410 (2.0%)	1823 (7.6%)	4300 (4.1%)	9594 (1.0%)	2735	24862 (3.0%)
2005	7619 (3.5%)	2692 (8.1%)	5193 (3.8%)	13010 (6.3%)	3524	32038 (5.2%)
2010	8823 (3.0%)	4354 (10.1%)	6254 (3.8%)	19539 (8.5%)	4817	43787 (6.4%)
2015	10024 (2.6%)	6714 (9.1%)	7342 (3.3%)	28816 (8.1%)	6538	59434 (6.3%)

te: Figures in parantheses indicate the average annual rate of growth in the preeciding period.

2.2.2. Kerala

e growth in the agriculture sector for Kerala is lower than that for Karnataka, and consumption level by 2015 grows to 1.87 times the consumption in 2000. The her growth rate of population in Kerala relative to Karnataka is reflected in the ectricity consumption growth in the domestic sector, which grows to 1.68 times the ar 2000 level.

the case of Kerala also, the growth in commerce exceeds that in industry, being at and 3.1 times for the high and low growth scenarios as compared to 3.1 and 1.8 es for industry.

The difference between the total consumption's growth rate for the high and low growth scenarios is larger in Kerala's case, being at 2.8 and 2.2 times the 2000 levels.

Table 2.4: Disaggregated electricity demand projections (low growth)

(GWh)

Year	Agriculture	Commercial	Domestic	Industrial	Others	Total
Karnataka						
2000	9313 (7.3%)	471 (3.9%)	2785 (3.5%)	6137 (3.6%)	881	19588 (5.6%)
2005	12588 (6.2%)	667 (7.2%)	3259 (3.2%)	7310 (3.6%)	1123	24946 (5.0%)
2010	16110 (5.1%)	941 (7.1%)	3762 (2.9%)	8950 (4.1%)	1402	31165 (4.6%)
2015	19822 (4.2%)	1297 (6.6%)	4291 (2.7%)	11080 (4.4%)	1719	38209 (4.2%)
Kerala						
2000	358 (5.4%)	1237 (6.4%)	2592 (3.7%)	3542 (4.1%)	672	8401 (5.1%)
2005	454 (4.9%)	1848 (8.4%)	3129 (3.8%)	4573 (5.2%)	870	10874 (5.3%)
2010	559 (4.2%)	2704 (7.9%)	3731 (3.6%)	6015 (5.6%)	1131	14139 (5.4%)
2015	670 (3.7%)	3815 (7.1%)	4356 (3.1%)	7888 (5.6%)	1455	18183 (5.2%)
Tamil Nadu						
2000	6410 (2.0%)	1798 (7.3%)	4300 (4.1%)	9495 (0.8%)	2719	24722 (2.9%)
2005	7619 (3.5%)	2455 (6.4%)	5193 (3.8%)	12078 (4.9%)	3380	30725 (4.4%
2010	8823 (3.0%)	3375 (6.6%)	6254 ((3.8%)	15691 (5.4%)	4220	38364 (4.5%)
2015	10024 (2.6%)	4569 (6.2%)	7342 (3.3%)	20385 (5.4%)	5231	47550 (4.4%)
Note: Figures in parantheses indicate the average annual rate of growth in the preeciding period.						

2.2.2.3. Tamil Nadu

The agriculture sector's consumption of electricity amongst the three states shows the lowest growth in Tamil Nadu over the period under consideration, growing to just above 1.5 times the 2000 level by 2015. The growth of the domestic sector is similar to that of Kerala at 1.7 times.

The trend of higher growth of the commercial sector as opposed to industry, continues in the case of Tamil Nadu also. For the high growth scenario, commerce

grows to 3.7 times its 2000 level while industry is restricted to 3.0 times the 2000 level. The corresponding figures for the low growth scenario are 2.5 times and 2.1 times for commerce and industry respectively.

Total electricity consumption grows to 2.4 times and 1.9 times the 2000 levels in the case of high and low growth scenarios respectively.

2.2.3. Installed capacity requirements

The total electricity requirement and the consequent installed capacity needed in the three states for the years 2000, 2005, 2010, and 2015 for the high growth scenario is given in Table 2.5, and the same for the low growth scenario is given in Table 2.6.

The transmission and distribution (T&D) losses are assumed to show a decline over time, and the values for T&D losses in the year 2000 are taken as 17.5%, 18.5%, and 15.0% for Karnataka, Kerala and Tamil Nadu respectively. These losses are assumed to decline to 13.5%, 14.5%, and 12.0% by the year 2015 for the three states respectively.

The system load factor (SLF) is taken to be 71% to arrive at the maximum MW demand placed on the system from the total energy (GWh) requirements after T&D losses. Finally, a reserve margin is added to the expected maximum system demand to arrive at the projections for installed capacity. This reserve margin is of the order of 30% of the total installed capacity required[1].

In the case of the high growth scenario, the overall annual growth rate of the installed capacity requirements hovers around five percent for Karnataka, while for Kerala it is just below six percent initially, but increases to over seven percent in the later years. For Tamil Nadu also, the rate of growth of the installed capacity requirement is lowest in 2000-05 at under five percent, but subsequently increases to over six percent.

In the case of the low growth scenario, installed capacity requirements during the periods 2000-05, 2005-10 and 2010-15 increase at an annual rate of 4.5%, 4.1% and 4.2% respectively. The corresponding growth rates are 4.8%, 4.9% and 5.2% for Kerala, and 4.0%, 4.3% and 4.4% for Tamil Nadu.

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[1] The 'peak demand' is divided by 0.7 to obtain the 'installed capacity required'.

The rates of growth of the installed capacity requirements are lower than that of the total electricity consumption because of decreasing transmission and distribution losses over time.

Table 2.5: Total electricity required and consequent installed capacity (high growth)

	Energy (GWh)		Demand (MW)		Growth rate of inst. capacity since 2000
Year	Energy reqd. for all sectors	Energy reqd. with T&D loss	Peak demand (SLF = .71)	Installed capacity reqd.	
Karnataka					
2000	19643	23810	3828	5469	-
2005	25463	30134	4845	6921	4.8%
2010	33299	38496	6189	8842	5.0%
2015	42886	49579	7971	11388	5.2%
Kerala					
2000	8470	10392	1671	2387	-
2005	11518	13794	2218	3168	5.8%
2010	16798	19646	3159	4513	7.3%
2015	24009	28081	4515	6450	7.4%
Tamil Nadu					
2000	24862	29249	4703	6718	-
2005	32038	36825	5921	8458	4.7%
2010	43787	49758	8000	11429	6.2%
2015	59434	67538	10859	15513	6.3%

Table 2.6: Total electricity required and consequent installed capacity (low growth)

	Energy (GWh)		Demand (MW)		Growth rate of inst. capacity since 2000
Year	Energy reqd. for all sectors	Energy reqd. with T&D loss	Peak demand (SLF = .71)	Installed capacity reqd.	
Karnataka					
2000	19588	23743	3817	5454	-
2005	24946	29522	4747	6781	4.5%
2010	31165	36029	5793	8275	4.1%
2015	38209	44173	7102	10146	4.2%
Kerala					
2000	8401	10308	1657	2368	-
2005	10874	13023	2094	2991	4.8%
2010	14139	16537	2659	3798	4.9%
2015	18183	21267	3419	4885	5.2%
Tamil Nadu					
2000	24722	29085	4676	6681	-
2005	30725	35316	5678	8112	4.0%
2010	38364	43595	7009	10013	4.3%
2015	47550	54034	8688	12411	4.4%

2.2.4. Sources of supplies

2.2.4.1. Central sector

In 1975, the Central government set up the National Thermal Power Corporation (NTPC) to construct, operate and maintain large thermal power stations. The major factor which was instrumental in the creation of NTPC was that the state electricity boards were strapped for funds and could not undertake capacity expansion programs. The power generated from NTPC's stations is usually shared by the different states in the region as per the Gadgil formula according to which the allocation of shares of power from a central sector generating station is made on the following basis:

(i) 15% of total generation installed capacity is reserved for the Centre for allocating this power to the various beneficiary states according to power needs at the time of generation.

(ii) The state in which the generating station is located gets 10% extra share.

(iii) The balance 75% power is allocated to the beneficiary states in the same ratio as the financial allocation to beneficiary states from the central revenue. The Gadgil formula also takes into account other factors such as area, population, and backwardness of the states.

Karnataka, Kerala and Tamil Nadu have a share in the output from NTPC's 2100 MW coal-fired thermal station at Ramagundam in Andhra Pradesh.

The Neyveli Lignite Corporation (NLC) under the Central government's Coal Ministry besides operating the lignite mines at Neyveli in Tamil Nadu, also owns and operates pit-head thermal stations with a total installed capacity of 2070 MW. The power generated from these units is shared by Karnataka, Kerala and Tamil Nadu besides Andhra Pradesh and Pondicherry.

All nuclear facilities are owned and operated by the Central government through the Nuclear Power Corporation (NPC). At present, there is one nuclear station operating near Madras (Kalpakkam) in Tamil Nadu with an installed capacity of 470 MW. Power generated from this station is shared by Andhra Pradesh, Karnataka. Kerala. Pondicherry. and Tamil Nadu. Another nuclear station (Kaiga) is under construction in Karnataka, with a planned installed capacity of 440 MW. An extension of the Kaiga station is also planned, which would bring the total installed capacity to 880 MW.

2.2.4.2. *Fuel-mix of installed capacities*

Neither the central, nor the state government have a clearly defined guideline for an optimal fuel-mix for the various states. However the Rajyadaksha committee appointed by the Government of India in the early eighties to advise the government regarding various aspects of power sector, recommended a ratio of 60:40 for thermal and hydro installed capacities.

The Central government has also decided not to allow any new generating stations to be based on gas oil as the fuel. This, however, is not applicable to generators which are installed as a back-up against failure of grid supply. The units which are set up to run on a continuous basis for sale of power to the grid are allowed to install generating units of the reciprocating type, and use heavy fuel oils instead of gas oil.

Usually, neither the central, nor the state government, specify the type of fuel to be used by an Independent Power Producer (IPP). The IPP selects the fuel based solely on its own economic considerations, but approval for the fuel-linkage is to be obtained from the Central Government.

Currently, hydro-electric stations account for about 47% of the power generated in the three states. About 49% of the total capacity available is coal/lignite based, and nuclear, wind, gas and gas oil account for the remainder. Table 2.7 gives the fuel-wise break-up of the total available generating capacity in the three states.

Table 2.7: Fuel mix of existing generating capacity

(MW)

State	Total	Hydro	%	Coal/ Lignite*	%	Gas Oil	%	Gas	%	Wind	%	Nuclear*	%
Karnataka	4033	2502	62	1373	34	128	3	0	0	0	0	30	1
Kerala	1970	1490	76	460	23	0	0	0	0	0	0	20	1
Tamil Nadu	6578	1948	30	4271	65	0	0	10	0	20	0	330	5
Total	12581	5940	47	6104	49	128	1	10	0	20	0	380	3

* Note: The share of the states from centrally owned stations is included in the coal/lignite and nuclear fuel based power stations.

Table 2.8 gives the expected fuel-wise break-up of the installed capacities till 2015 in the three states. The fuel-mix was estimated on the basis of existing proposals and the likelihood of their being commissioned in a particular period. This assessment was based on a number of factors, including the current status of the projects with respect to clearances from the Central Electricity Authority, whether a power purchase agreement has been entered into with the state government or not, etc. Based on these factors, the projects which were very likely to come up were

given a probability rating of 100%, while the ones which could go either way were given a probability of success of 40%.

The plant-wise break-up of the new capacities and the expected period of commissioning is given in Appendices 2.1, 2.2 and 2.3 for Karnataka, Kerala and Tamil Nadu respectively.

Table 2.8: Fuel-mix of installed capacities till year 2015

(MW)

	Hydro	Coal/ Lignite*	Gas Oil	Nuclear*	Fuel Oil	Gas	Vacuum Residue	Naphtha	Wind	Total
Karnataka										
1995	2502	1373	128	30	0	0	0	0	0	4033
	62%	34%	3%	1%	0%	0%	0%	0%	0%	100%
2000	2645	1833	128	140	670	0	0	97	0	5513
	48%	33%	2%	3%	12%	0%	0%	2%	0%	100%
2005	2801	3053	128	250	968	40	0	97	0	7337
	38%	42%	2%	3%	13%	1%	0%	1%	0%	100%
2010	3232	4053	128	360	968	340	0	457	0	9538
	34%	42%	1%	4%	10%	4%	0%	5%	0%	100%
2015	3577	5053	128	470	968	340	0	457	0	10993
	33%	46%	1%	4%	9%	3%	0%	4%	0%	100%
Kerala										
1995	1490	460	0	20	0	0	0	0	0	1970
	76%	23%	0%	1%	0%	0%	0%	0%	0%	100%
2000	1735	660	0	35	0	0	0	0	0	2430
	71%	27%	0%	1%	0%	0%	0%	0%	0%	100%
2005	1745	860	0	50	92	60	500	0	0	3307
	53%	26%	0%	2%	3%	2%	15%	0%	0%	100%
2010	1865	1055	0	65	92	560	500	678	0	4723
	39%	22%	0%	1%	2%	12%	11%	14%	0%	100%
2015	1865	1640	0	80	92	1060	500	1678	0	6915
	27%	24%	0%	1%	1%	15%	7%	24%	0%	100%
Tamil Nadu										
1995	1948	4271	0	330	0	10	0	0	20	6579
	30%	65%	0%	5%	0%	0%	0%	0%	0%	100%
2000	1948	4481	0	360	0	135	0	0	20	6944
	28%	65%	0%	5%	0%	2%	0%	0%	0%	100%
2005	2003	5781	0	390	400	465	0	0	120	9159
	22%	63%	0%	4%	4%	5%	0%	0%	1%	100%
2010	2153	6941	0	420	820	1965	0	0	120	12419
	17%	56%	0%	3%	7%	16%	0%	0%	1%	100%
2015	2153	8901	0	450	820	3465	0	0	120	15909
	14%	56%	0%	3%	5%	22%	0%	0%	1%	100%

* Note: The share of the states from centrally owned stations is included in the coal/lignite and nuclear fuel based power stations.

2.2.5. Pricing

The Electricity (Supply) Act (E(S)A), 1948, governs the sale of electricity to the consumers by the state electricity boards (SEBs). While the E(S)A enjoins the SEBs to carry on their operations, as far as practicable, without incurring losses, the guidelines for the actual determination of tariffs exist only in a broad sense in the Act. The Act does not go into the specifics of price determination, but only sets the condition that SEBs earn a return of 3% on their assets.

In all the three states, there exists a high level of cross subsidies in electricity prices across the sectors. Commercial and industrial consumers, particularly medium and large consumers, are charged higher per unit rates compared to the average cost of generation and supply, while electricity for the domestic sector is sold at a subsidised rate. The agriculture sector gets free supply of electricity in Tamil Nadu, and only pays a nominal amount in Karnataka and Kerala.

The three SEBs have moved from a simple energy rate to differential rates for different block of consumers. Inverted or increasing block tariffs are used to discourage high consumption. Consumers are charged an increasing rate for consuming more or for higher connected loads. This also partially takes care of the social objective of providing electricity at subsidised rates to the consumers in the low income categories. The three SEBs have two-part tariff for the high-voltage consumers, wherein separate charges are levied for energy consumed (kWh) and the power demand (kW).

The overall average tariffs in the three states for 1992-93 to 1994-95 are given in Table 2.9.

Table 2.9: Changes in overall average tariff

	1992-93		1993-94		1994-95	
	(paise/kWh)	(¢/kWh)	(paise/kWh)	(¢/kWh)	(paise/kWh)	(¢/kWh)
Karnataka	99.35	2.84	106.75	3.05	111.84	3.20
Kerala	73.96	2.11	81.40	2.33	93.87	2.68
Tamil Nadu	107.12	3.06	128.34	3.67	146.33	4.18

The average tariff has been highest in Tamil Nadu over the years, followed by Karnataka, and then Kerala.

The average sector-wise tariff in 1995-96 for the three states along with the average cost of supply of power in paise/kWh and US ¢/kWh, is given in Table 2.10.

Table 2.10: Average cost of supply and average electricity tariff (1995-96)

(paise/kWh)

State	Domestic	Commercial	Agriculture	Industrial	Average tariff	Cost of supply
Karnataka	109.20	413.00	20.50	230.40	142.48	145.90
(Share of sales)	(16%)	(3%)	(43%)	(35%)		
Kerala	64.30	150.00	22.00	111.10	98.46	116.70
(Share of sales)	(33%)	(14%)	(4%)	(45%)		
Tamil Nadu	92.10	237.50	0.00	227.50	146.33	178.00
(Share of sales)	(16%)	(6%)	(27%)	(43%)		

Note: The percentage figures for sales do not sum to 100 as 'others' have not been covered here.

(¢/kWh)

State	Domestic	Commercial	Agriculture	Industrial	Average tariff	Cost of supply
Karnataka	3.12	11.80	0.59	6.58	4.07	4.17
(Share of sales)	(16%)	(3%)	(43%)	(35%)		
Kerala	1.84	4.29	0.63	3.17	2.81	3.33
(Share of sales)	(33%)	(14%)	(4%)	(45%)		
Tamil Nadu	2.63	6.79	0.00	6.5	4.18	5.09
(Share of sales)	(16%)	(6%)	(27%)	(43%)		

Notes: 1. The percentage figures for sales do not sum to 100 as 'others' have not been covered here.
2. The conversion rate used is Rs 35.00/US $

Karnataka Electricity Board has revised its tariffs from July 1, 1996. It is expected that the other two boards will also announce new tariffs shortly.

2.3. COAL

2.3.1. Existing demand

In the southern states of Tamil Nadu, Kerala and Karnataka, coal is consumed mainly in the thermal power stations and to a lesser extent in cement plants. As of now, there is only one integrated steel plant in these states. There are no other major coal consuming industries.

The current demand for coal, broken down by the three major consumer sectors; thermal power stations, cement plants and iron & steel plants, is given in Table 2.11.

Table 2.11: Existing demand for coal as on March 31, 1995

(million tons)

State	Thermal Power Station*	Cement Plant	Iron & Steel Plant	Total
Karnataka	2.78	1.38	0.41	4.57
Kerala	0.00	0.10	0.00	0.10
Tamil Nadu	19.32	1.15	0.00	20.47
Note: Even though the three states have a share in power generated, NTPC's Ramagundam station is not included here as it is located in Andhra Pradesh.				

2.3.2. Projected demand

Currently the only major coal consuming industries in the three states are thermal power stations and cement plants, and one integrated steel plant. A few more iron and steel plants are slated to come up in the future. As we foresee only these three industries; viz. power, cement and iron/steel; as major consumers of coal, the demand projections for coal/lignite have been done on the basis of planned additions.

Table 2.12 gives the projected coal demand in the states of Karnataka, Kerala and Tamil Nadu till the year 2015.

Table 2.12: Coal demand projections

(million tons)

Year	2000	2005	2010	2015
Karnataka				
Thermal Power Station	4.62	9.50	13.50	17.50
Cement Plant	1.68	2.48	4.34	6.20
Iron/Steel Plant	10.69	23.29	26.89	26.89
Total	**16.99**	**35.27**	**44.74**	**50.59**
Kerala				
Thermal Power Station	0.80	1.60	2.38	4.72
Cement Plant	0.10	0.10	0.10	0.10
Iron/Steel Plant	0.00	0.00	0.00	0.00
Total	**0.90**	**1.70**	**2.48**	**4.82**
Tamil Nadu				
Thermal Power Station	20.16	25.36	30.00	37.84
Cement Plant	1.35	1.79	2.22	2.22
Iron/Steel Plant	4.55	4.55	4.55	4.55
Total	**26.06**	**31.70**	**36.77**	**44.61**
Note: Even though the three states have a share in power generated, NTPC's Ramagundam station is not included here as it is located in Andhra Pradesh.				

2.3.3. Sources of supplies (All India)

Coal is supplied to the thermal power stations from mines in Andhra Prades (Singareni), Orissa (Talcher), Maharashtra (Nagpur), and West Bengal (Raniganj) Neyveli near Madras in Tamil Nadu has lignite deposits, and Neyveli Lignit Corporation operates pit-head generating units using lignite. Ib Valley in Orissa i likely to emerge as a major supplier of coal in the future.

Figure 2.4 shows the location of major coal fields in India.

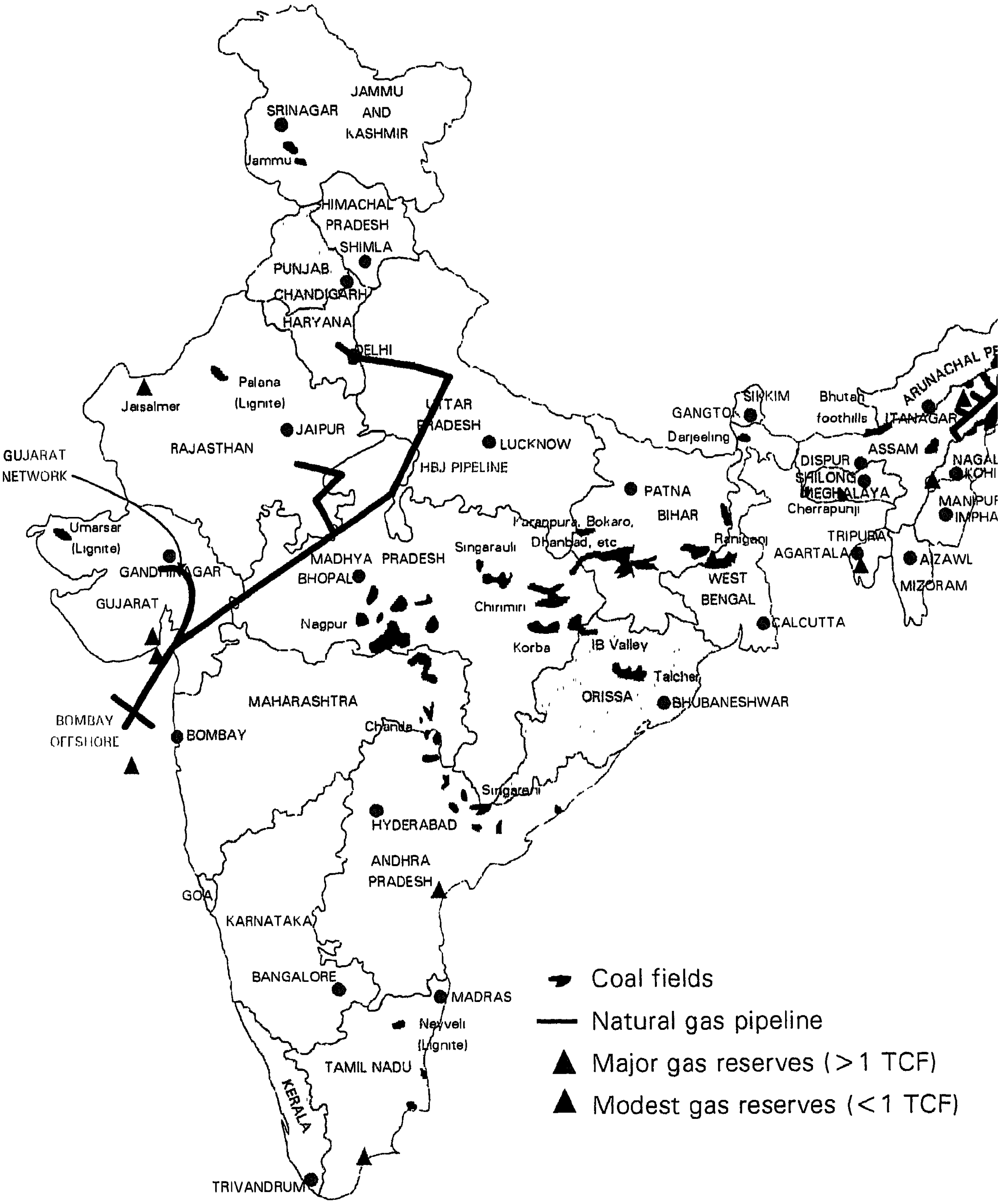
2.3.3.1. Constraints on transport of coal (All India)

Rail is the major mode of movement of coal in the country. Since the coa production centres are concentrated in the eastern and central parts of the country long distance movement of coal by rail becomes essential. In 1995-96, the railway carried 156.62 MMT of coal produced in the country.

The traditional sources of supply of coal since several decades have been Ranigunj an Dhanbad-Jharia coal-fields. The railways have been investing in strengthening of th routes originating from these areas. These coal-fields have now started declining i production and in the last few years coal-fields such as Talcher and Ib Valley in Oriss Korba in Madhya Pradesh and North Karanpura in Bihar are emerging as new source Movement of coal on these newer routes is becoming difficult due to limitation of lin capacity. Indian Railway will also be facing a shortage of rolling stock for movement c coal if sufficient finances are not made available to them. The pressure on the ra transport network is likely to increase further as the demand for coal increases in th future.

Other transport modes employed for coal movement are mainly road and captiv modes like rail based merry-go-round system (MGR), conveyor belts and aeri ropeways besides sea routes. Though the MGR system is rail based, it i considered a separate entity as the wagons associated with the system ar dedicated to moving coal on a continuous basis. This system is only suitable fc coal consuming plants in a radius of about 50 km from a coal mine. Currently, ther are still some thermal power stations which use conventional rail transport despit being located at a pit-head. The adoption of the MGR system by them would fre precious coal transporting capacity of the Indian Railway.

Figure 2.4: Coal and gas fields in India



The railways have also started a "own your wagon" scheme under which either the coal mine or the consumer owns the wagons. This scheme is expected to enable the railways to further free up resources for investment in track upgradation work.

The share of rail mode in coal transport has declined from about 70% in 1984-85 to 56% in 1995-96. This is largely because of increase in the movement of coal by MGR system whose share has increased from 6% to 21% in the same period. The pressure on the rail transport network is likely to increase further as the demand for coal increases in the future. In the last decade, movement of coal to pit-head power stations through MGR system has increased considerably. The details of mode-wise coal movement is given in Table 2.13.

Table 2.13: Over-land mode-wise coal movement in million metric tons

Mode	1984-85		1994-95		1995-96	
Rail	98.0	(70)	148.94	(57)	156.62	(56)
Road	27.0	(19)	49.83	(19)	54.46	(19)
MGR/own wagons	8.0	(6)	50.78	(19)	57.13	(21)
Belt	4.6	(3)	6.18	(3)	6.37	(2)
Ropeway	3.4	(2)	5.65	(2)	5.92	(2)
Total	141.0	(100)	261.38	(100)	280.50	(100)
Note: Figures in parenthesis indicate percent share.						

2.3.3.1. Constraints on transport of coal to the Southern states

Coal requirement of some consumers in Southern India which include power stations and cement plants are met by moving coal by rail-cum-sea route. Haldia, Paradeep and Vizag (Vishakhapatnam) ports handle coal shipments. During the year 1994-95 about 10 MMT of coal was moved by rail-cum-sea route.

At present there are 11 major ports and 163 minor/intermediate ports in India. The major ports handle more than 93% of the total traffic. The commodities handled by these ports are much more than the designed capacity. In 1993-94 these ports handled 179.26 MMT cargo against the designed capacity of 172.59 MMT. Many ports are working at more than 100 % of their capacity. The growth rate of cargo handled in 1993-94 over 1992-93 was 8.1 %

Table 2.14: Capacities of major ports

(MMT/year)

Port	As on 31.3.93	As on 31.3.94
Calcutta & Haldia	23.53	23.65
Paradeep	7.65	7.65
Vishakhapatnam (Vizag)	23.05	23.35
Madras	22.07	22.07
Tuticorin	5.10	6.10
Cochin	10.66	10.80
New Mangalore	9.55	9.55
Marmagoa	15.92	15.92
Bombay	26.80	26.80
Kandla	20.80	20.80
Jawaharlal Nehru Port Trust (JNPT)	5.90	5.90
TOTAL	**171.03**	**172.59**

Table 2.15: Commodity-wise capacity of major ports

(MMT/year)

Commodity	As on 31.3.93	As on 31.3.94
Coal	7.00	8.00
POL	78.00	78.00
Iron Ore	41.50	41.50
Fertiliser & Raw Material	7.95	7.95
Others including containers	36.58	37.14
TOTAL	**171.03**	**172.59**

Not much capacity addition has taken place either as a whole or more particularly for handling incremental coal traffic. The capacity building in port, apart from other natural constraints, is highly capital intensive and with the current resource crunch, not much can be expected in the short term.

Although Ennore near Madras is being developed as a satelite port to receive coal by sea, the rail-cum-sea rote presents several problems. Apart from the constraints on rail movement, double handling is involved both at the loading and discharge ports. If the receiving terminal station is located inland, a further movement of coal by rail or road becomes necessary. Also coal storage has to be provided at both transhipment points. It is therefore anticipated that it will not be possible to move coal to the extent required to the Southern states, and the impact of this on the proposed fuel-mix capacities of the three states is discussed further in Chapter 4.

2.3.4. Pricing

The Central government administers the pit-head price of coal while leaving the price paid by the consumers largely unregulated. Thus, to arrive at the delivered market price, to the pit-head price of coal are added the loading/transport charges at the pit-head, processing charge, royalty, cess, duties and taxes, and the transportation and handling cost from the colliery to the consumer. The details of these charges are discussed in the next chapter.

The pit-head price of coal has been fixed as Rs 264.20 per ton for grade 'F' coal, the grade of coal used in thermal power stations. The pit-head price for grade 'D' coal, or the coal used in cement plants, has been fixed as Rs 591.00 per ton.

2.4. HYDROCARBONS

2.4.1. Existing demand

2.4.1.1. Karnataka

Karnataka's total petroleum product consumption of 3.2 million metric tons (MMT) per annum accounts for about 5% of the all-India consumption of 65 MMT in 1994-95. The product-wise consumption over the 5 years from 1990 is shown in Table 2.16 and the market segment wise break up of the products in Table 2.17. 1993-94 is the latest year for which product-wise break up is available.

Table 2.16: Consumption of petroleum products in Karnataka

('000 metric tons)

Product	**1990-91**	**1991-92**	**1992-93**	**1993-94**	**1994-95**	**RoG since 1990-91**
LPG	109	123	135	150	170	9%
Gasoline	219	221	232	252	275	5%
Naphtha	140	137	99	99	128	-2%
Kerosene	439	441	452	452	459	1%
Jet Fuel	50	58	59	73	75	8%
Gas oil	1074	1170	1296	1410	1609	8%
Fuel oil	318	321	295	308	402	5%
Others	111	108	132	144	134	4%
Total	**2460**	**2579**	**2700**	**2888**	**3252**	**6%**

Table 2.17: Sector-wise demand for petroleum products in Karnataka in 1993-94

('000 metric tons)

	Domestic	Transport	Industry					Misc.	Total
			Power	Fertiliser	Petrochemical	Others	Total		
LPG	135	-	-	-	-	14	14	1	150
Gasoline	-	252	-	-	-	-	-	-	252
Naphtha	-	-	-	100.0	-	-	-	-	100
Kerosene	452	-	-	-	-	-	-	-	452
Jet Fuel	-	73	-	-	-	-	-	-	73
Gas oil	-	1238	10	-	-	91	101	71	1410
Fuel oil	-	-	1	52	-	70	123	185	308
Others	-	-	-	-	-	-	-	-	144
Total	**587**	**1563**	**11**	**152**	**0**	**175**	**238**	**257**	**2889**

2.4.1.2. Kerala

The Kerala economy is largely agrarian, hence the state is characterised by a low level of industrialisation. Consequently, the state's oil consumption at 2.4 MMT in 1994-95, is less than 4% of the all-India level. Tables 2.18 and 2.19 respectively show the growth of petroleum products in Kerala and their end use wise break up.

Table 2.18: Consumption of petroleum products in Kerala

('000 metric tons)

Product	**1990-91**	**1991-92**	**1992-93**	**1993-94**	**1994-95**	**RoG since 1990-91**
LPG	81	92	91	100	116	7%
Gasoline	148	144	144	157	174	3%
Naphtha	185	177	133	167	184	0%
Kerosene	262	256	266	270	273	1%
Jet Fuel	25	26	33	35	40	10%
Gas oil	701	755	813	969	1064	9%
Fuel oil	335	318	319	324	354	1%
Others	174	206	224	178	214	4%
Total	**1911**	**1974**	**2023**	**2200**	**2419**	**5%**

Table 2.19: Sector-wise demand for petroleum products in Kerala in 1993-94

('000 metric tons)

	Domestic	Transport	Industry					Misc.	Total
			Power	Fertiliser	Petrochemical	Others	Total		
LPG	90	-	-	-	-	9	9	1	100
Gasoline	-	157	-	-	-	-	-	-	157
Naphtha	-	-	-	167	-	-	167	-	167
Kerosene	270	-	-	-	-	-	-	-	270
Jet Fuel	-	35	-	-	-	-	-	-	35
Gas oil	-	856	6	-	-	60	66	47	969
Fuel oil	-	-	9	98	-	217	324	-	324
Others	-	-	-	-	-	-	-	-	178
Total	**360**	**1048**	**15**	**265**	**0**	**286**	**566**	**48**	**2200**

2.4.1.3. Tamil Nadu

Oil consumption in Tamil Nadu is the highest among the 3 states. The consumption at 5.6 MMT in 1994-95 accounts for 9% of the all-India consumption. The product-wise consumption over the 5 years till 1994-95 is shown in Table 2.20 and the end use wise break up of the products in Table 2.21.

Table 2.20: Consumption of petroleum products in Tamil Nadu

('000 metric tons)

Product	**1990-91**	**1991-92**	**1992-93**	**1993-94**	**1994-95**	**RoG since 1990-91**
LPG	204	220	238	257	285	7%
Gasoline	238	241	244	262	291	4%
Naphtha	461	493	472	443	487	1%
Kerosene	656	642	662	666	671	0%
Jet Fuel	50	58	60	71	84	11%
Gas oil	2064	2150	2195	2285	2488	4%
Fuel oil	830	876	870	869	904	2%
Others	311	337	354	360	417	6%
Total	**4814**	**5017**	**5095**	**5209**	**5627**	**3%**

Table 2.21: Sector-wise demand for petroleum products in Tamil Nadu in 1993-94

('000 metric tons)

	Domestic	Transport	Industry					Misc.	Total
			Power	Fertiliser	Petrochemical	Others	Total		
LPG	231	-	-	-	-	23	23	2	257
Gasoline	-	262	-	-	-	-	-	-	262
Naphtha	-	-	-	443	-	-	443	-	443
Kerosene	666	-	-	-	-	-	-	-	666
Jet Fuel	-	71	-	-	-	-	-	-	71
Gas oil	-	1993	18	-	-	154	172	120	2285
Fuel oil	-	-	81	341	54	35	511	358	869
Others	-	-	-	-	-	-	-	-	360
Total	**231**	**2326**	**99**	**784**	**54**	**212**	**1149**	**480**	**5213**

2.4.2. Projected demand

Product-wise demand projections to 2006/07 have been carried out by the Oil Co-ordination Committee (OCC) in 1994. This study has used those projections and has extrapolated them to 2015 after consultation with oil industry experts about the future growth potentials in the various states.

OCC was commissioned by the Ministry of Petroleum and Natural Gas to assess product-wise demand and had a broad based representation from the Planning Commission, Ministry of Surface Transport, Department of Fertilisers, Department of Chemicals, Ministry of Steel, and Ministry of Power.

Various methodologies have been followed in the forecasting exercise. While for the purpose of forecasting LPG demand, state-level field surveys were conducted, for products like Naphtha and fuel oil, an end-use based approach was adhered to. End-use consumption of fuel oil was analysed and it was found that bulk of the product is consumed in the power, fertiliser, and petrochemical industry. Based on the planned growth of these industries in each state, projections of fuel oil demand have been made. Projections of petroleum products in the three states are shown in Table 2.22.

Table 2.22: Projected demand of petroleum products

('000 metric tons)

Year	2000	2005	2010	2015	RoG since 2000
Karnataka					
LPG	484	599	711	879	4.1%
Gasoline	411	608	892	1311	8.0%
Naphtha	290	290	393	575	4.7%
Kerosene	497	506	513	550	0.7%
Gas oil	2168	2871	3792	5003	5.7%
Fuel oil	293	343	504	799	6.9%
Kerala					
LPG	253	311	367	451	3.9%
Gasoline	250	370	543	798	8.0%
Naphtha	362	362	451	593	3.3%
Kerosene	322	328	332	355	0.6%
Gas oil	1498	1984	2620	3456	5.7%
Fuel oil	162	166	221	317	4.6%
Tamil Nadu					
LPG	612	713	806	938	2.9%
Gasoline	427	632	927	1362	8.0%
Naphtha	521	521	543	572	0.6%
Kerosene	619	629	637	683	0.7%
Gas oil	3489	4620	6101	8049	5.7%
Fuel oil	595	643	738	854	2.4%

2.4.3. Sources of supplies

The hydrocarbon reserves in Southern India are located in the Krishna-Godavari Basin in Andhra Pradesh. The Cauvery Basin in South-eastern Tamil Nadu also has modest gas reserves. The gross and net production of natural gas in Tamil Nadu in 1994-95 was 98 and 16 million cubic meters respectively. For Andhra Pradesh, it was 640 and 618 million cubic meters respectively. The difference between the gross and net production is the quantity of natural gas flared.

In 1993-94, Andhra Pradesh and Tamil Nadu together produced 536,000 tons of crude oil, while between April 1994 and September 1995, their production of crude oil stood at 305,000 tons.

While explorations are continuing, no new discoveries of hydrocarbon reserves have been made in the region, except for the two basins mentioned above.

The existing refineries are located at Madras and Narimanam in Tamil Nadu; Cochin in Kerala; and Mangalore in Karnataka (see Table 2.23).

Table 2.23: Refining capacity

(MMT/year)

Location	Installed capacity as on May 1, 1996
Madras, Tamil Nadu	6.50
Narimanam, Tamil Nadu	0.50
Cochin, Kerala	7.50
Mangalore, Karnataka	3.00

2.4.4. Pricing

The basic ceiling selling prices (ex-storage point at the refinery gate) of petroleum products is given in Table 2.24.

Table 2.24: Prices of petroleum products

Product	Price in Rupees	Price in US Dollars
Gas oil (HSD)	Rs 6575/kilo litre	$ 188/kilo litre
Furnace Oil (for non-fertilisers)	Rs 5896/kilo litre	$ 168/kilo litre
Furnace Oil (for fertilisers)	Rs 3656/kilo litre	$ 104/kilo litre
Naphtha (for non-fertilisers)	Rs 6683/MMT	$ 191/MMT
Naphtha (for fertilisers)	Rs 4840/MMT	$ 138/MMT
Notes: 1. These prices are exclusive of Customs and Excise duties and also state sales tax. 2. The conversion rate has been taken as Rs 35/US $.		

Pricing of hydrocarbons is discussed in greater detail in Chapter 3.

CHAPTER 3
ENERGY POLICIES AND REGULATORY MATTERS

Electricity is legislated upon both by the Central, as well as the State governments. The Central Electricity Authority advises the Ministry of Power at the Centre, while at the state level, State Electricity Boards (SEB) are statutory organisations looking after development of the power sector. Tariffs for purchase of power from private producers as well as for sale to ultimate consumers are set by the state governments in consultation with the SEB. The Central government has the final say in granting clearances for power projects in all cases, as it approves the fuel linkages. Coal and hydrocarbons are under the control of the Central government. A major portion of the cost of coal to a consumer is the transportation charge from the mines to the consumption centre. Oil companies have an assured return on the capital employed due to the current pricing regime. However, the administered pricing regime has started undergoing some change as parallel marketing for kerosene, LPG, LSHS and lubricants has now been allowed. In the power sector, environmental issues are mostly related to hydro projects though awareness has started to increase with regard to pollution from coal based thermal power stations.

3.1. STRUCTURE AND POLICIES

3.1.1. Electricity

The Constitution of India defines the powers of the Central Government, State Governments and Local Bodies in urban and rural areas. The Seventh Schedule of the Indian Constitution defines the independent powers of the Union and State Governments in the Union and State Lists. It also outlines the areas of shared responsibility between the two, in the Concurrent List. For subjects in the Concurrent List, both the Union and the State Government have the powers to legislate, though the Union legislation will always have precedence over the State legislation.

Electricity is mentioned in entry number 38 under List 3, which is the Concurrent List of the Seventh Schedule. This means that electricity comes under the purview of both the Central and State governments and the powers to regulate through legislation and to tax remain with both the Union and the State Governments.

It was after independence that the Government of India formalised the responsibility of the public sector in power development by enacting the Electricity (Supply) Act in 1948. Under Section 3 of this Act, the Central Electricity Authority (CEA) was constituted and charged with the responsibility of developing a sound, adequate and uniform national policy in relation to the control and utilisation of national power resources. The CEA, inter alia, conducts the techno-economic appraisal of the

project reports in respect of setting up of generating stations in the country and issues techno-economic clearances for projects. Under section 5 of this act, the State Electricity Boards (SEBs) were created as statutory organisations responsible for the efficient and economic development of the power sector in their respective states.

At the central level, within government, power as a subject is dealt by the Ministry of Power (MOP) and is headed by a senior Union Minister. The structure of the MOP is provided in Appendix 3.1. Figure 3.1 shows the various power sector organisations. Each state government has a separate Department of Power or Energy with administrative powers over the State Electricity Board (SEB). The organisation chart for an SEB is given in Appendix 3.2.

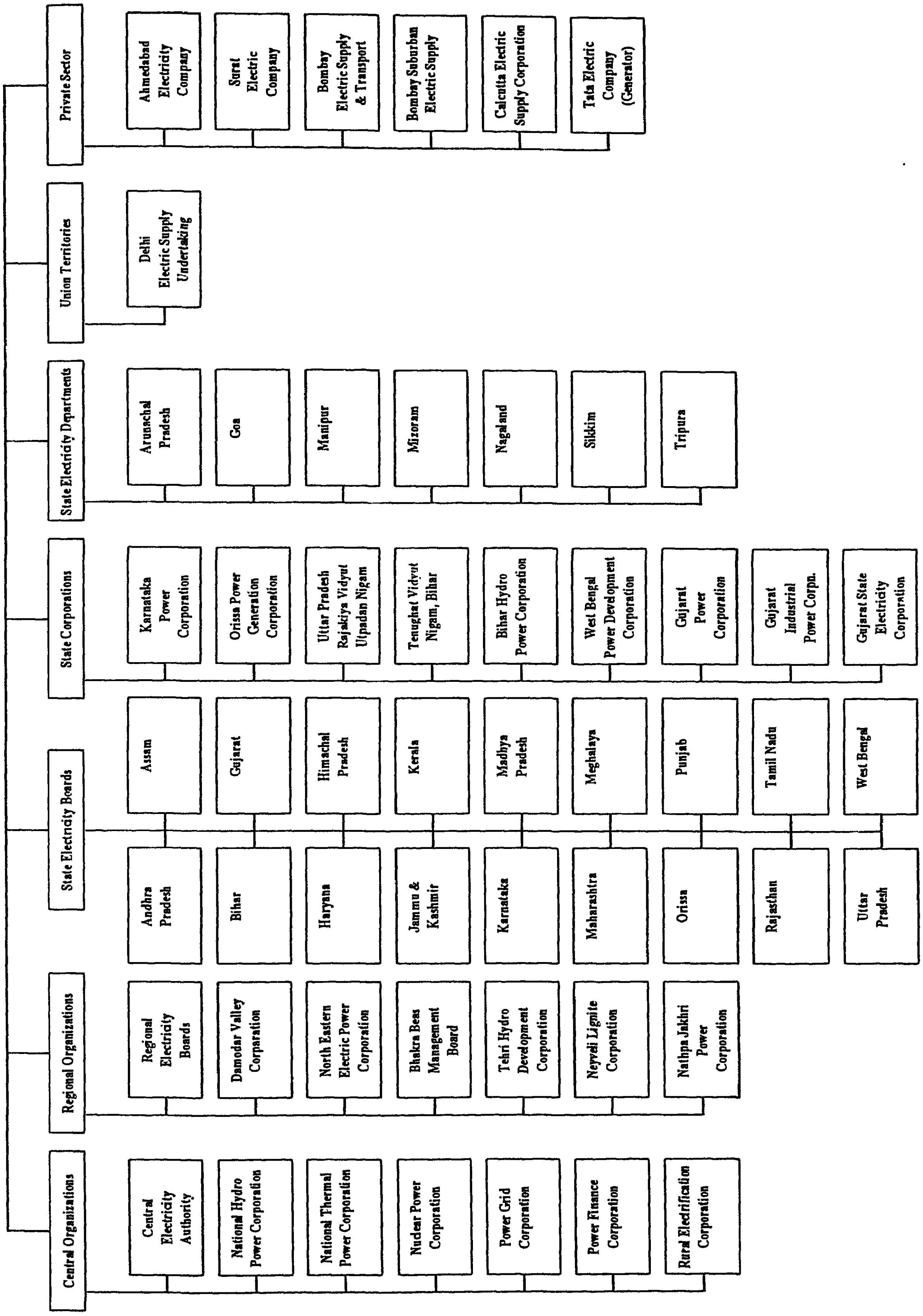
The SEBs are responsible for setting the electricity tariffs applicable to the different sectors, but it is the state government which is the final approving authority on the tariffs. Due to this, more often than not, the tariffs for domestic and agriculture consumers are set based on political considerations rather than economic.

The state governments in consultation with the respective SEBs, are also authorised to clear power generation projects which involve a capital expenditure of less than Rs 4 billion, provided the project is competitively bid. This translates to projects of approximately 100 MW capacity, taking the average capital cost to be Rs 40 million per megawatt. Any project which exceeds this limit, has to obtain clearances from the Central Electricity Authority. There is a proposal before the central government to raise this limit to include power stations of up to 700 MW capacity and a decision on this is expected soon. A flow chart detailing the techno-economic clearance process by the CEA is included in Appendix 3.3.

The SEBs are at present the only customers of power generated by the Independent Power Producers (IPPs). The tariff at which power is purchased by a SEB from an IPP is decided through the competitive bidding process and/or negotiations between the IPP, SEB, and the state government.

While the state governments are authorised to clear projects of up to 100 MW capacity, the fuel linkages have to be approved by the relevant ministries in the central government. Coal is handled by the Ministry of Coal, hydrocarbons by Ministry of Petroleum and Natural Gas, and water for hydro schemes by the Ministry of Water Resources. The Ministry of Environment and Forests at the centre is the

Figure 3.1: Power sector organisations


Central Organizations
Central Electricity Authority
National Hydro Power Corporation
National Thermal Power Corporation
Nuclear Power Corporation
Power Grid Corporation
Power Finance Corporation
Rural Electrification Corporation
Regional Organizations
Regional Electricity Boards
Damodar Valley Corporation
North Eastern Electric Power Corporation
Bhakra Beas Management Board
Tehri Hydro Development Corporation
Neyveli Lignite Corporation
Nathpa Jakhri Power Corporation
State Electricity Boards
Andhra Pradesh
Bihar
Haryana
Jammu & Kashmir
Karnataka
Maharashtra
Orissa
Rajasthan
Uttar Pradesh
Assam
Gujarat
Himachal Pradesh
Kerala
Madhya Pradesh
Meghalaya
Punjab
Tamil Nadu
West Bengal
State Corporations
Karnataka Power Corporation
Orissa Power Generation Corporation
Uttar Pradesh Rajakiya Vidyut Utpadan Nigam
Tenughat Vidyut Nigam, Bihar
Bihar Hydro Power Corporation
West Bengal Power Development Corporation
Gujarat Power Corporation
Gujarat Industrial Power Corpn.
Gujarat State Electricity Corporation
State Electricity Departments
Arunachal Pradesh
Goa
Manipur
Mizoram
Nagaland
Sikkim
Tripura
Union Territories
Delhi Electric Supply Undertaking
Private Sector
Ahmedabad Electricity Company
Surat Electric Company
Bombay Electric Supply & Transport
Bombay Suburban Electric Supply
Calcutta Electric Supply Corporation
Tata Electric Company (Generator)

final authority on environmental clearances. The detailed procedures for obtaining clearances for a new power plant are given in Appendix 3.4.

Therefore, while the state governments have some autonomy in the approval process for power stations of up to 100 MW capacity, the central government still has the final say on the approval of a project.

Also important to note is that all proposals for foreign investment in power, or in any other industry for that matter, whether through setting up of a new company or through the purchase of equity in an existing company, need to be approved by the Foreign Investment Promotion Board (FIPB) now under the Ministry of Industry but formerly under the Prime Minister's Office.

3.1.1.1. Competitive bidding process

In this process, bids are invited from various firms interested in the project in two parts; viz., (i) Technical proposal (excluding financial terms), (ii) Financial proposal.

The technical proposal is opened in the presence of authorised representatives of each firm and a comparison is made with the specifications issued at the time of inviting bids. In case there are major deviations from the specifications, the firm submitting the particular technical proposal is termed as non-responsive and its offer rejected. In case there are minor variations from the specifications, the firm is asked to indicate the reduction/increase in price for bringing the technical proposal in conformity with the issued specifications. Similar discussions are held with representatives of other firms.

After the technical proposals have been discussed with all the prospective bidders, the financial proposals of the short-listed bidders are opened in the presence of representatives of firms. The financial proposal of each firm is then modified based on decisions taken by discussing the technical proposals and the work is awarded to the lowest cost bidder.

3.1.2. Coal

The Ministry of Coal is responsible for development and exploitation of coal and lignite reserves in India. The subjects allocated to the Ministry under the Government of India (Allocation of Business) Rules, 1961, as amended from time to time, are as follows:

(i) Exploitation and development of coking coal and non-coking coal and lignite deposits in India.

(ii) All matters relating to production, supply, distribution and pricing of coal.

(iii) Development and operation of coal washeries.

(iv) Administration of Coal Mines (Conservation and Development) Act, 1974 (28 of 1974).

(v) Administration of the Coal Mines Provident Fund and Miscellaneous Provisions Act, 1948 (46 of 1948) and all matters relating to the Coal Mines Provident Fund Organisation.

(vi) Administration of residual matters relating to the Coal Mines Labour Welfare Organisation since abolished with effect from 1.10.1986.

(vii) Administration of the rules under the Mine Act, 1952 (32 of 1952) for levy and collection of excise duty on coke and coal produced and despatched from mines.

(viii) Administration of Coal Bearing Areas (Acquisition and Development) Act, 1957 (20 of 1957).

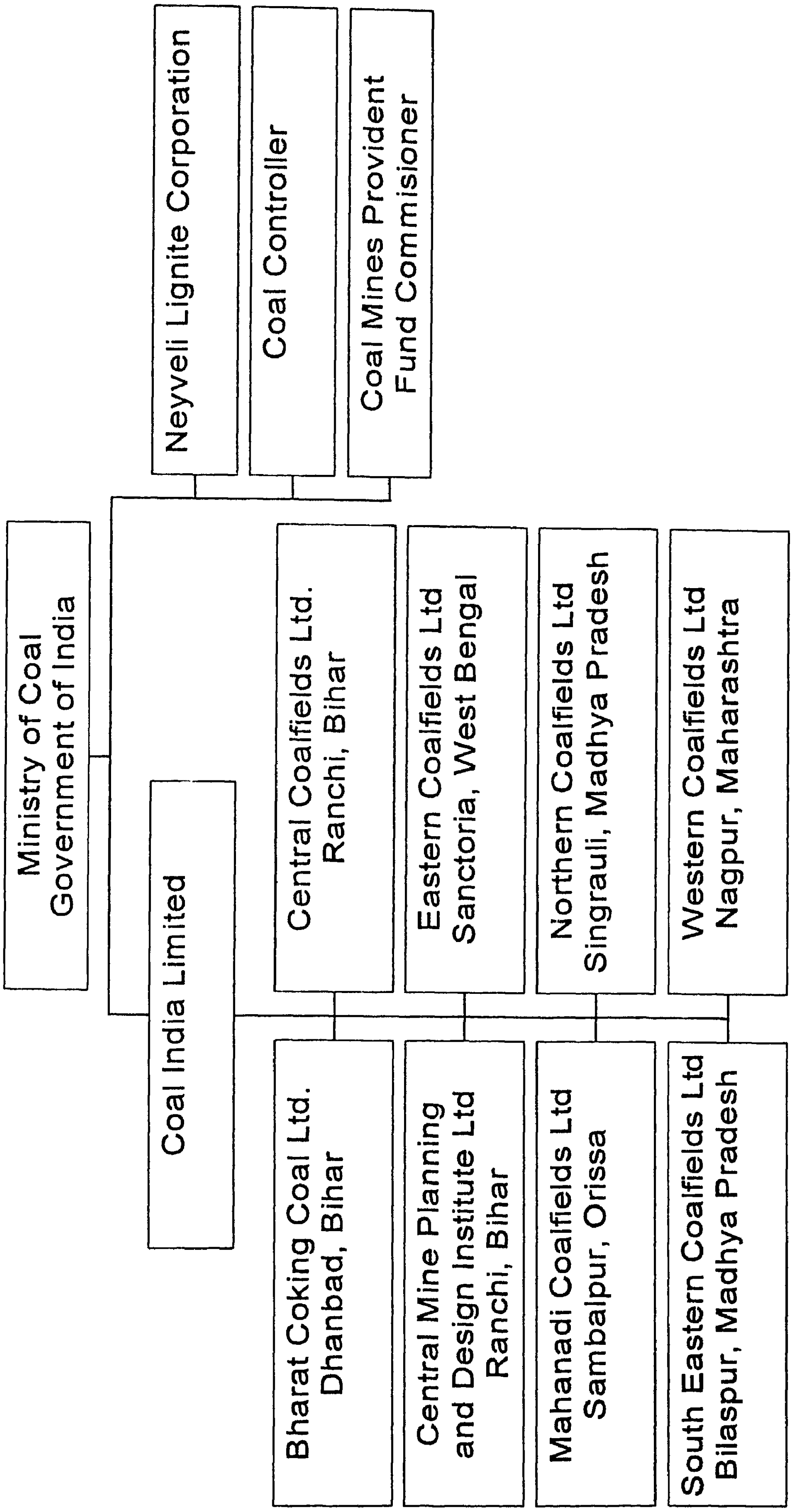
(ix) Administration of Public Sector Enterprises dealing with coal and lignite.

(x) Administration of Mines and Minerals (Regulation and Development) Act, 1957 (67 of 1957) and other Union Laws in so far as the said Act and other Laws relating to Coal and Lignite and use of sand for stowing purposes.

(xi) All business incidental to the administration of above activities including matter concerning the state governments.

The Ministry has under its administrative control the Coal India Limited (CIL), a Public Sector Undertaking, along with its eight subsidiary companies (see Figure 3.2). CIL with its headquarters at Calcutta in West Bengal is the holding company in respect of these subsidiaries. It is also the apex body in the coal industry and is responsible for laying down the policy guidelines and co-ordination work of subsidiaries. It also does the investment, planning, manpower, management, purchase of heavy machinery, financial budgeting etc. on behalf of all its subsidiaries. While seven of the subsidiaries of the Coal India Limited are producing companies directly engaged in raising and distribution of coal, the Central Mine Planning and Design Institute Limited is the planning, designing and engineering company whose function is to render expert service on mineral exploration, planning and designing of coal projects, coal beneficiation, coal utilisation, environmental management, etc. and to transfer foreign technology for assimilation in Indian conditions.

Figure: 3.2: Coal industry organisations


Ministry of Coal
Government of India
Neyveli Lignite Corporation
Coal Controller
Coal Mines Provident Fund Commisioner
Coal India Limited
Central Coalfields Ltd. Ranchi, Bihar
Eastern Coalfields Ltd Sanctoria, West Bengal
Northern Coalfields Ltd Singrauli, Madhya Pradesh
Western Coalfields Ltd Nagpur, Maharashtra
Bharat Coking Coal Ltd. Dhanbad, Bihar
Central Mine Planning and Design Institute Ltd Ranchi, Bihar
Mahanadi Coalfields Ltd Sambalpur, Orissa
South Eastern Coalfields Ltd Bilaspur, Madhya Pradesh

The Ministry of Coal also has under its administrative control the Neyveli Lignite Corporation with headquarters at Neyveli in Tamil Nadu. The company is engaged in exploitation of lignite deposits and generation of lignite-based power in Tamil Nadu.

The Government of India and the state government of Andhra Pradesh have also formed a joint-venture company, Singareni Collieries Company Limited (SCCL). The equity capital is shared in the ratio of 51:49 between the state and central governments respectively. This company operates coal mines located in the state of Andhra Pradesh.

The Ministry of Coal has two other organisations under its administrative control, namely the Coal Controller's Organisation, and the Coal Mines Provident Fund Organisation.

The Coal Controller's Organisation is a subordinate office of the Ministry of Coal, having its headquarters at Calcutta and two field offices at Dhanbad and Asansol. The Coal Controller has certain statutory functions to perform. His statutory authority is derived from the following statutes:

- (i) Colliery Control Order, 1945, which authorises the Coal Controller to:
    - (a) monitor the quality of coal and settle the complaints against grading and sub-standard despatches of coal;
    - (b) grant permission and opening and reopening of seams and mines; and
    - (c) undertake distribution of coking coal.
- (ii) Coal Mines (Conservation and Development) Act, 1974 and Rules made thereunder, which authorise the Coal Controller to:
    - (a) make recommendations for payment of subsidy towards stowing and protective works for conservation purposes;
    - (b) assess and collect stowing excise duty;
    - (c) function as Secretariat of the Coal Conservation and Development Advisory Committee; and
    - (d) monitor coal shipment to power houses and cement plants.
- (iii) Statistics Act 1953, which authorises the Coal Controller to:
    - (a) collect statistical information regarding production and value of coal, distribution etc. and to public documents; and
    - (b) Coal Bearing Areas (Acquisition and Development) Act 1957 & Rules made thereunder.

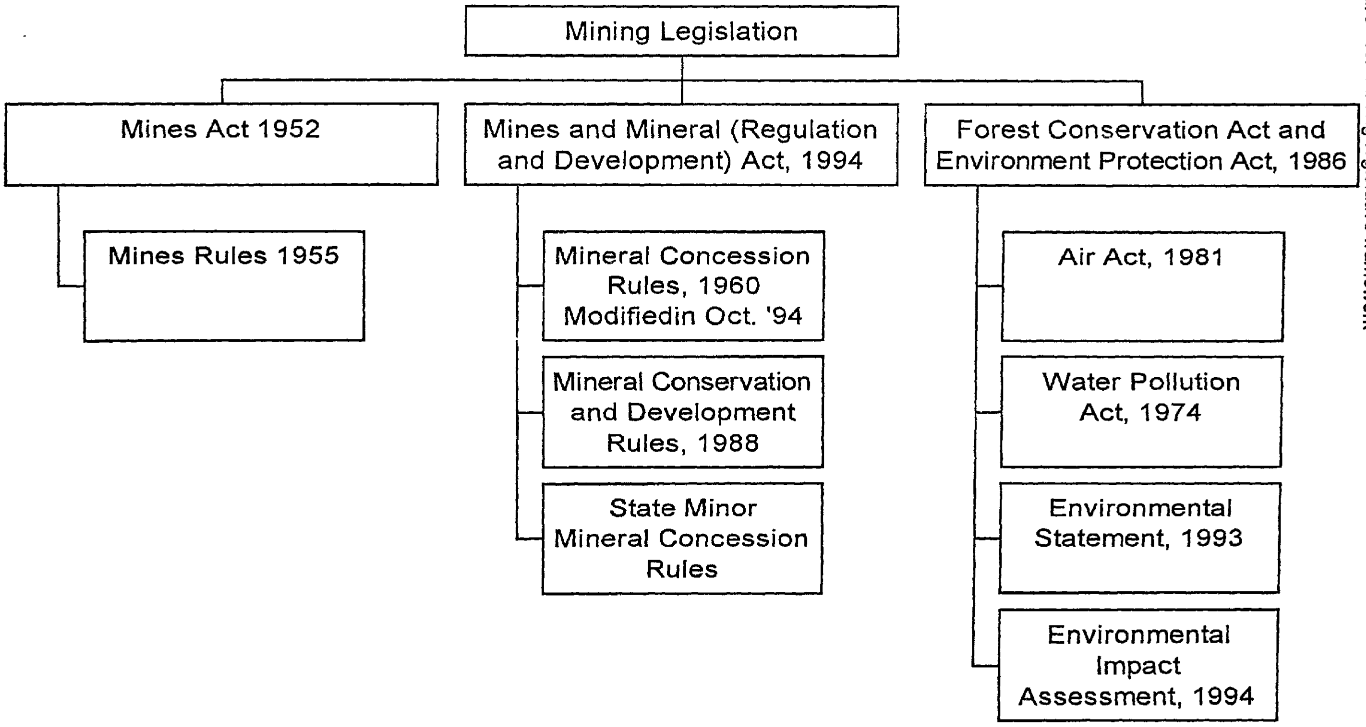

Mining Legislation
Mines Act 1952
Mines and Mineral (Regulation and Development) Act, 1994
Forest Conservation Act and Environment Protection Act, 1986
Mines Rules 1955
Mineral Concession Rules, 1960 Modifiedin Oct. '94
Mineral Conservation and Development Rules, 1988
State Minor Mineral Concession Rules
Air Act, 1981
Water Pollution Act, 1974
Environmental Statement, 1993
Environmental Impact Assessment, 1994

Figure 3.3: Mining legislative framework

- Under this act, coal controller functions as a "Hearing Authority" for disposal of objections under section 8 of the above act against acquisition of coal bearing land by the coal companies

The various Acts and Rules which govern coal mining activities in India are shown in Figure 3.3.

3.1.3. Hydrocarbons

The Ministry of Petroleum and Natural Gas under the Government of India is responsible for the exploration and exploitation of petroleum resources, including natural gas. Its role extends to the production, refining, supply, distribution, marketing and pricing of petroleum products and natural gas. Exports and imports of crude oil, petroleum products and gas are also under its control.

The tasks of the Ministry are exercised through various public sector undertakings (PSUs) , their subsidiaries and other organisations, shown in Figures 3.4 and 3.5.

Figure 3.4: Organisation of the Indian hydrocarbon sector

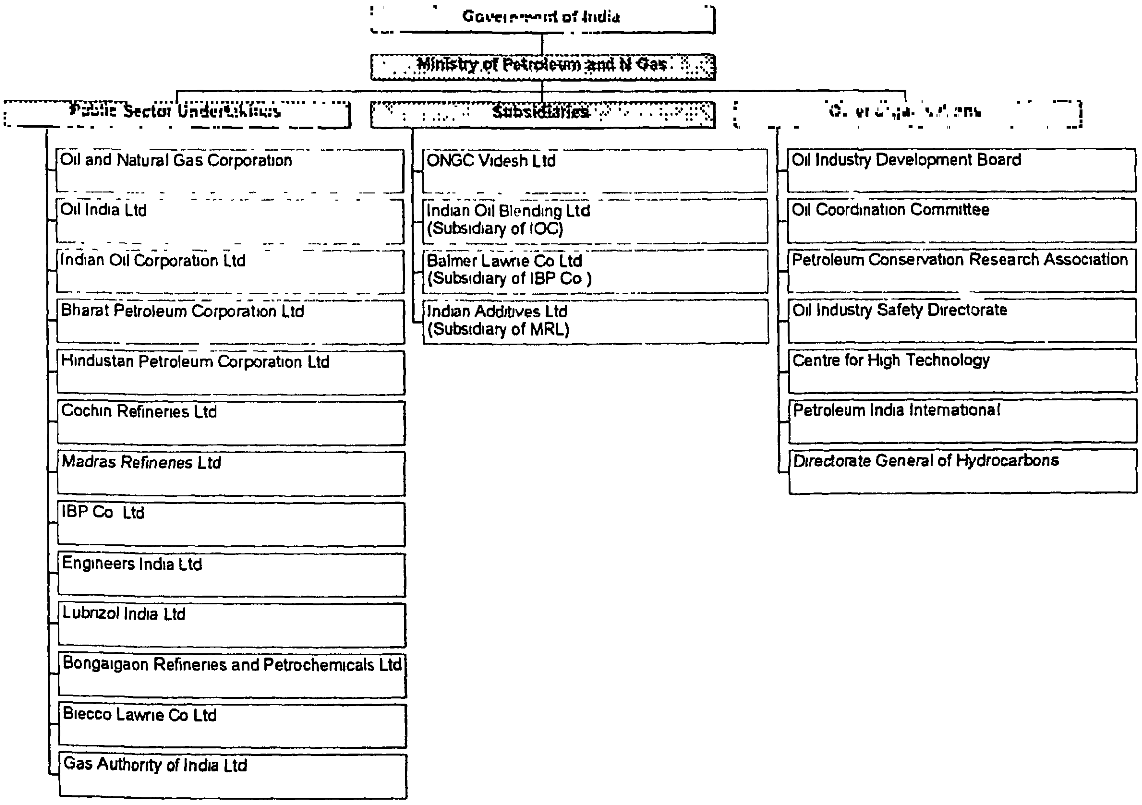
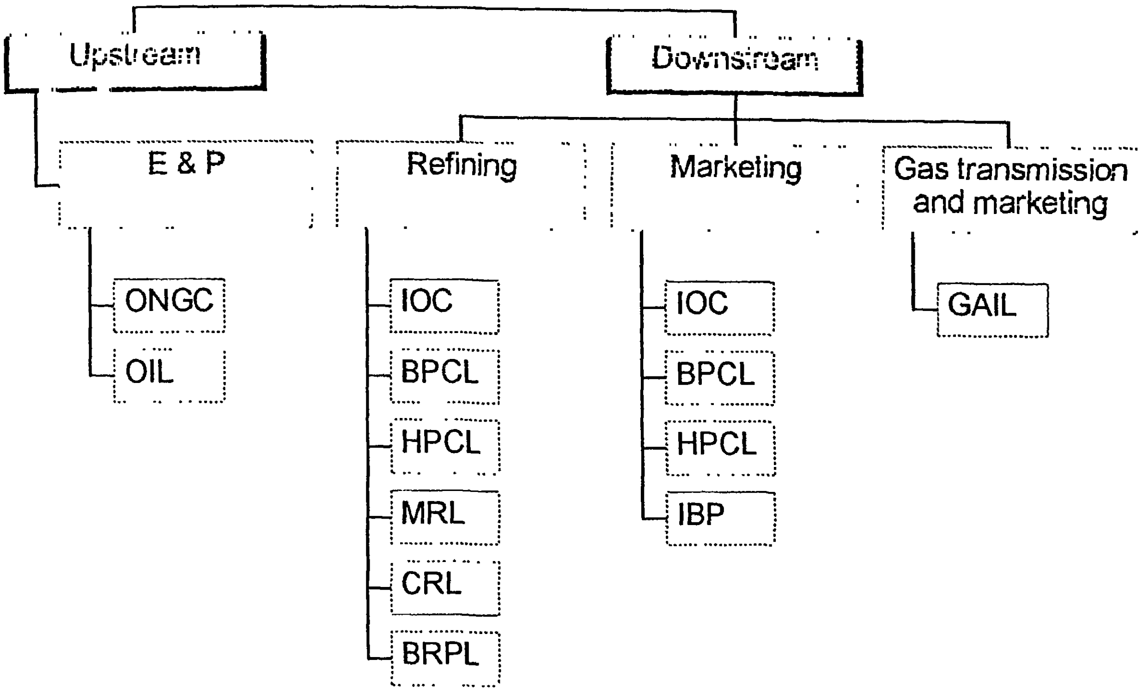

Government of India
Ministry of Petroleum and N Gas
Public Sector Undertakings
Subsidiaries
Other Organisations
Oil and Natural Gas Corporation
Oil India Ltd
Indian Oil Corporation Ltd
Bharat Petroleum Corporation Ltd
Hindustan Petroleum Corporation Ltd
Cochin Refineries Ltd
Madras Refineries Ltd
IBP Co Ltd
Engineers India Ltd
Lubrizol India Ltd
Bongaigaon Refineries and Petrochemicals Ltd
Biecco Lawrie Co Ltd
Gas Authority of India Ltd
ONGC Videsh Ltd
Indian Oil Blending Ltd (Subsidiary of IOC)
Balmer Lawrie Co Ltd (Subsidiary of IBP Co)
Indian Additives Ltd (Subsidiary of MRL)
Oil Industry Development Board
Oil Coordination Committee
Petroleum Conservation Research Association
Oil Industry Safety Directorate
Centre for High Technology
Petroleum India International
Directorate General of Hydrocarbons

Figure 3.5: PSUs under the Ministry of Petroleum and Natural Gas



3.2. PRICING STRUCTURE, TAXES AND DUTIES

3.2.1. Electricity

The states are empowered to levy a State Electricity Duty (SED) on sales of electricity if they so wish. As on March 31, 1996, Tamil Nadu did not levy any SED on electricity, while Karnataka and Kerala levied a duty of 4.69 and 9.13 paise/kWh. This translates to about 3.29% and 9.27% respectively of the two states' average tariff.

3.2.2. Coal

3.2.2.1. Transportation charges at pit-head

Where coal is transported beyond a distance of 3 km to the loading point, the coal companies are entitled to charge additional transport costs from the purchasers at the following rates.

- Distance more than 3 km but not more than 10 km, Rs 18.00 per ton.
- Distance more than 10 km but not more than 20 km, Rs 35.00 per ton.

3.2.2.2. Royalty

The Central Government has revised the rates of royalty on coal w.e.f. 11.10.1994. The enhancement of rates has been made keeping in view the interests of both the consumers and the coal producing states and at the same time ensuring the

development of coal mining industry. The royalty on coal production is collected by the concerned state governments. The revised rates are given in Table 2.2.

Table 3.1: Revised rates of royalty on coal

(Rs/ton)

Coal group	**Royalty w.e.f. 1.8.91**	**Royalty w.e.f. 11.10.94**	**Percentage of average price/ton**
Group I (Coking SG I, II, WG I)	150	195	24
Group II (Coking Coal WG II, III, SC I, II, Non-Coking A, B)	120	135	24
Group III (Coking Coal WG IV, Non-Coking C)	75	95	20
Group IV (Non-Coking D, E)	45	70	20
Group V (Non-Coking F, G)	25	50	20
Group IV (Coal produced in Singareni, Andhra Pradesh)	70	75	15

3.2.2.3. Cess, duties and taxes

Cess: Cess is not applicable in case of the states mentioned here.

Stowing excise duty: A uniform charge of Rs 3.50 per ton is levied on coal price as stowing excise duty.

Taxes: Central Sales Tax is levied on the price of coal at the pit-head at a uniform rate of 4% if the coal is transported outside the state where it is produced.

3.2.2.4. Transportation cost from colliery to consumer end

The rail tariff per ton km for coal movement by railroad gradually decreases from Rs 0.74 per tkm for a haul of 100 km to Rs 0.54 per tkm for a haul of 1300 km, in slabs of about 4 km. The average lead for coal movement by rail is about 700 km and the tariff per tkm was Rs 0.55 in 1995. The rail tariff per tkm has been increasing regularly over the years.

The delivered price of grade ‘F’ coal, which is the coal used in thermal power stations, for selected distances has been estimated and is given in Table 3.2, and the same information is presented in Table 3.3 for grade ‘D’ coal which is used in cement plants. It can be seen from the table that the transportation charge is a major component of the delivered price of coal. The share of transportation charge in the delivered price of coal increase from 27% for a 200 km haul to 68% for a 1300 km haul, and becomes 75% for a 2000 km haul (for consumers in the western and southern parts of the country). Figure 3.6 shows the share of the various components in the delivered price of grade ‘F’ coal. The rail transport charges given

here are pre July 16, 1996; and do not take into account the 10% increase in freight charges announced in the Railway Budget.

Table 3.2: Delivered price of grade 'F' coal for selected distances

(Rs./ton)

Components	**200 km**	**500 km**	**1000 km**	**1300 km**	**2000 km**
Administered pit-head price	264.20	264.20	264.20	264.20	264.20
Royalty	50.00	50.00	50.00	50.00	50.00
Stowing excise duty	3.50	3.50	3.50	3.50	3.50
Central Sales tax (4%)	12.70	12.70	12.70	12.70	12.70
Pit-head price	330.40	330.40	330.40	330.40	330.40
Rail transport	124.00	279.00	551.00	699.00	981.00
Price to consumer	454.40	609.40	881.40	1029.40	1311.40
Note: Excludes states of West Bengal and Assam					

Figure 3.6: Share of different components in delivered price of grade 'F' coal

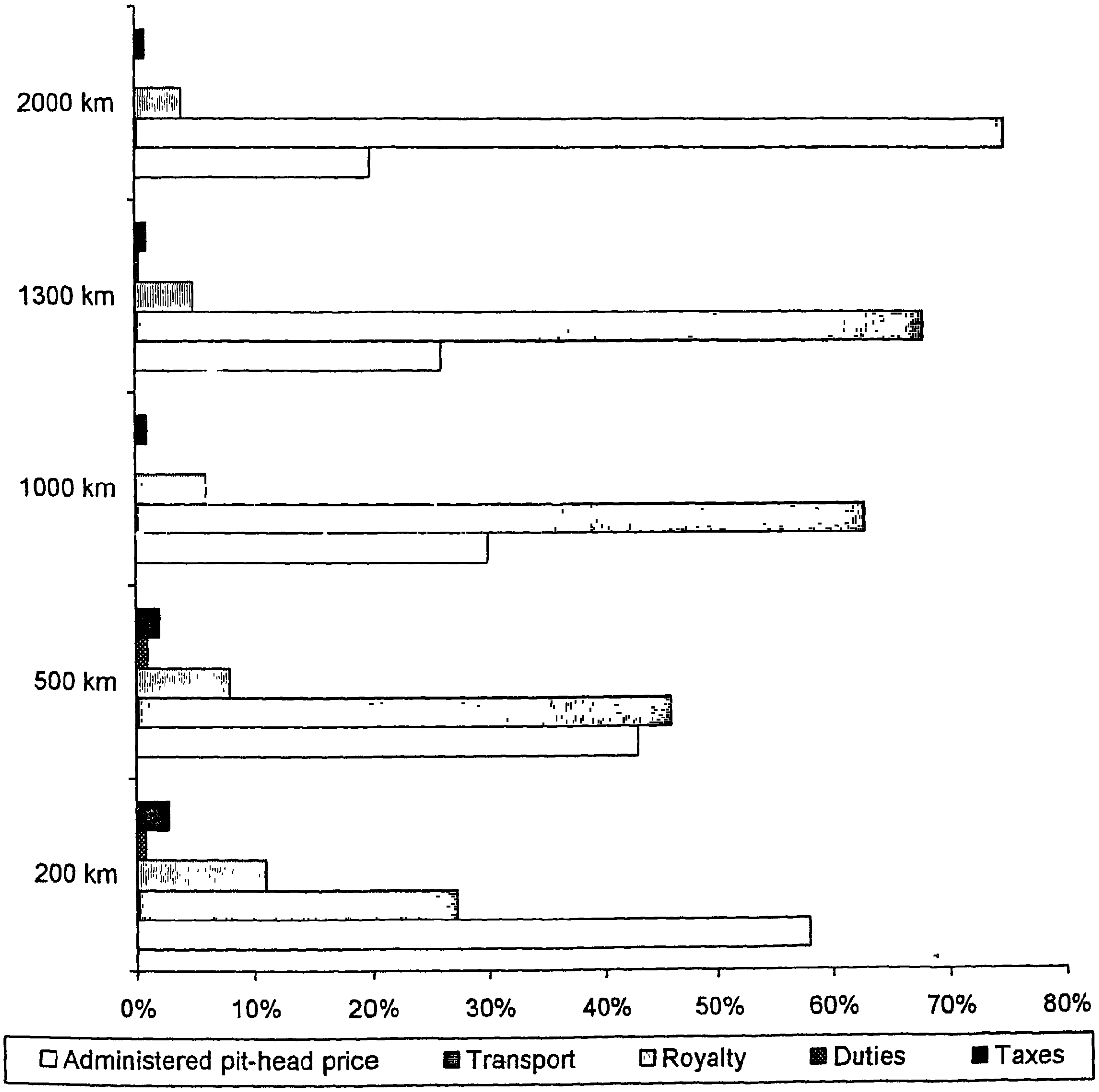


Table 3.3: Delivered price of grade 'D' coal from Singareni for cement plants

(Rs/ton)

Components	200 km	500 km	1000 km
Administered pit-head price	591.00	591.00	591.00
Royalty	75.00	75.00	75.00
Stowing Excise Duty	3.50	3.50	3.50
Central Sales Tax (4%)	26.80	26.80	26.80
Pit-head price	696.30	696.30	696.30
Rail transport	124.00	279.00	551.00
Price to consumer	820.30	975.30	1247.30

There is an import duty of 5% on imports of coking coal by the steel industry. For non-coking coal (used in power stations), the import duty is 35% of the CIF value.

In the future, the prices of domestic non-coking coal for use in power plants are expected to follow the current trend of 4% growth per annum.

3.2.3. Hydrocarbons

Pricing of crude oil and petroleum products in India was based on the concept of "import parity" until the first oil crisis in 1973. The consumer prices were related to the notional C.I.F. value of imported products and, in addition, included excise/custom duties, marketing and distribution margins and profits of oil companies. A number of committees were set up during the 1960s to examine the question of petroleum product pricing. All these committees recommended continuance of the "import parity" concept, though computation of the notional FOB prices of petroleum products for determining the final consumer prices varied from time to time.

The first change in this system of "import parity" prices was brought about in 1974 following the steep increase in crude oil prices in the international market. Until then, domestic producers were allowed a price in line with the prices prevailing in the international market. However, the indigenous producers were not allowed higher international prices from 1974 onwards and the prices they were paid were pegged at the earlier level. This led to the beginning of crude pool price concept (i.e. pooling of the cost of imported and indigenous crude) for building up petroleum product prices and emergence of the Crude Oil Prices Equalisation (COPE) account for making adjustments in crude cost of refineries processing imported and indigenous crude.

The Oil Prices Committee (OPC) that was set up by the Government of India in 1974 submitted its reports in 1975 and 1976. The recommendations of this Committee formed the basis for a new pricing regime that has continued till now with small variations. The Committee took note of the changes that had taken place in respect of the quantum of indigenous crude production and domestic refining capacity and felt that the import parity principle did not reflect the inter-refinery differences in respect of the type of crude oils, production pattern, size and complexity. The OPC, therefore, recommended that the pricing of major petroleum products at the refinery points be based on domestic cost, i.e. retention concept, by taking into account the delivered cost of crude oil (which is a pooled cost of imported and indigenous crude oil), the cost of refining of crude oil and reasonable return on the capital employed. Such a retention concept was recommended for marketing activities as well. These recommendations were accepted by the Government and a regime of retention pricing was introduced in two stages in 1975 and 1977 replacing the system based on the principle of import parity. This system continues to be in practice with certain variations till now. Essentially, the present pricing regime is a "cost plus" system worked out on the basis of normative costs plus a return on net worth/capital employed. This pricing system is applicable to different operations starting from upstream oil production to marketing and distribution of products. The costs of operations of different companies are "pooled" to ensure that the product prices from the storage points (the primary pricing points) are the same irrespective of the sources from which they come, and that price of any product at any location is the same for all companies marketing at that location.

3.2.3.1. Pricing of crude oil

The national oil companies, i.e. Oil & Natural Gas Corporation (ONGC) and Oil India Limited (OIL) engaged in exploration and production of oil and gas, are now allowed a 15% post tax return on capital employed after taking into account normative costs of production, survey and development drilling expenditure, amortised exploratory drilling expenditure and depreciation of assets.

3.2.3.2. Prices of products at refinery points

Like the producing companies, the refineries in the country are also allowed retention prices for each ton of product. For the purpose of calculating the retention price for the products for each refinery, a standard throughput and standard product pattern (including refinery-specific fuel & loss) is decided for each refinery after taking note of crude processing capacity and the likely crude mix, secondary processing facilities available, and other relevant technical factors. Costs are also determined on a normative basis for each refinery separately for chemicals,

catalysts, consumables, utilities, salaries and wages, overheads, depreciation, repairs and maintenance. The refineries are allowed a 12% post tax return on the net worth (equity plus reserves), the normative refining costs and the cost of crude oil. While the retention price per metric ton of crude throughput is so determined for each refinery, this retention price per ton of crude throughput is allocated to different petroleum products on the basis of a set of relative indices (e.g. kerosene 1.0, LPG 1.15, gas oil 0.95). This set of indices for different products under the controlled pricing system is uniform for all refineries. However, as the product pattern, the capital stock, as also the costs differ from refinery to refinery, the prices that the refineries are entitled for any particular petroleum product differ between refineries in spite of application of a uniform set of indices on the retention price per ton of crude throughput. In case the refineries are able to increase their crude throughput over the standard throughput, they are allowed, as an incentive, the same retention price (including return on the net worth) for the incremental quantity, though such incremental output involves incremental variable cost only. Conversely, there is a similar penalty if the throughput is lower than the standard throughput.

In short, while the delivered cost of crude oil is equalised by and large for all the refineries in the country, the retention price for each ton of crude throughput and then for each ton of petroleum product vary considerably from refinery to refinery depending upon the capital stock, the secondary processing facilities, the product pattern, the total refining capacity and other costs.

These different retention prices for each petroleum product for different refineries are thereafter pooled on a weighted basis to arrive at a uniform ex-refinery price for each petroleum product throughout the country.

Table 3.4: Prices of hydrocarbons (ex-refinery gate) w.e.f. July 1996

		Basic ceiling selling price	
Product	Selling unit	Rupees	US Dollars
Gas oil (HSD)	KL	6575	188
Furnace oil			
For non-fertilisers	KL	5896	168
For fertilisers	KL	3656	104
Naphtha			
For non-fertilisers	MMT	6683	191
For fertilisers *	MMT	4840	138

Notes: 1. These prices are exclusive of Customs and Excise duties, and also state sales tax.
2. The conversion rate has been taken as Rs 35/US $

Table 3.5: Duties and taxes on petroleum products

Type of levy	Product	Unit	Amount
Cess	Crude	Rs/MMT	900.00
Royalty	Crude	Rs/MMT	528.00
Royalty	Natural gas	%	10.00
Customs duty	Crude	%	35.00
Customs duty	LPG	%	15.00
Customs duty	Naphtha	%	0.00
Customs duty	Fuel oil	%	30.00
Customs duty	Gas oil	%	30.00
Customs duty	Gasoline	%	30.00
Customs duty	Natural gas	%	0.00
Excise/CVD/Surcharge	Crude	%	0.00
Excise/CVD/Surcharge	LPG	%	10.00
Excise/CVD/Surcharge	Naphtha (for fertiliser)	Rs/KL	5.50
Excise/CVD/Surcharge	Naphtha (non-fertiliser)	%	10.00
Excise/CVD/Surcharge	Fuel oil (for fertilisers)	%	0.00
Excise/CVD/Surcharge	Gas oil	%	10.00
Excise/CVD/Surcharge	Gasoline	%	20.00
Excise/CVD/Surcharge	Natural Gas	%	0.00

3.2.3.3. Marketing and distribution charges

While the ex-refinery prices for each product are uniform, a similar pooling arrangement is made for working out the marketing and distribution margins. Normative estimates are made for each marketing company for installation, distribution and administration costs on the basis of expected throughput of each company. Besides, allowances are made for stock losses as also for operating expenses. Finally, a 12% post-tax return is allowed on the net fixed assets, in addition to interest on the borrowed capital. These retention prices for marketing companies are pooled and a uniform marketing margin is added to the ex-refinery prices for each product.

3.2.3.4. Other adjustments

Freight Surcharge Pool (FSP) Amount

This surcharge is levied on each product to meet the cost of transportation of products by coastal tankers, barges, pipelines and other transportation costs not specifically allowed.

Cost and Freight (C&F) Surcharge

This surcharge is mainly levied to recover the higher cost of imported products. In effect, this surcharge allows pooling the cost of domestic and imported products.

Product Price Adjustment (PPA)

These adjustment for each product are essentially decided on the basis of the Government's decision for cross subsidisation of products. The following approach has been followed for different products through such price adjustments:

i) As Kerosene is used mostly by relatively less affluent people, its price has been kept low.

ii) Prices of Naphtha and Fuel Oil for fertiliser production have been kept low to restrict the cost of fertiliser produced; the prices of these products are much higher for non-fertiliser use.

iii) Similarly, LPG prices for domestic use are kept much lower than LPG prices for commercial or industrial uses.

iv) Prices of Gasoline and Jet Fuel are higher to provide the cross-subsidisation on the products mentioned above.

Consumer prices

The prices ex-storage points thus include the following :

i) Ex-refinery price
ii) Excise duties
iii) Marketing Margin
iv) FSP
v) C&F surcharge
vi) PPA

Prices at ports, pipeline terminals and tap. off points, and upcountry installations and depots are arrived at by adding the appropriate coastal, pipeline or rail transportation cost to the ex-refinery price.

The final consumer price consists of ex-storage price and local taxes plus in the case of LPG, gasoline and gas oil retailing charges and local delivery costs from the storage point to the consumption point.

3.2.3.5. The impact

The current pricing regime introduced since the mid-1970s has enabled the oil companies to recover their costs so computed and obtain an assured return on the capital employed. The fact that practically all the hydrocarbon exploration and production companies as also the marketing and refining companies are owned by the Government has facilitated the linkages between prices at different stages ensuring that across the country the consumer price of a product is, by and large, the same except for transportation and delivery costs and local taxes/duties. About

90% by volume of the products sold in the country are under the purview of this administered pricing system, while the pricing of the balance products are left to the marketing companies to decide. The adjustments of prices allowed to different companies for the purpose of pooling of these prices are done through a number of pool accounts administered by the Oil Coordination Committee, attached to the Ministry of Petroleum and Natural Gas. In the absence inadequate availability of alternate fuels like coal and electricity, petroleum products have acted as a "swing fuel" and their demands have not been significantly affected in the medium term even when price increases have taken place.

A degree of insulation of the domestic prices against the volatile nature of international oil and product prices has been achieved by pooling of the lower cost indigenous crude and the higher cost imported crude. However, the advantage of the lower pooled crude oil cost has not been passed on to the consumers on a uniform basis for all products because of the policy objectives of the Government. A system of cross-subsidy among different products has resulted in uneven increases in prices of different products over the years. Kerosene prices have thus hardly increased in the last few years. Naphtha and Fuel Oil prices for non-fertiliser use are about 38% and 60% higher than the corresponding prices for fertiliser use. The price of gasoline is more than double the gas oil price.

3.2.3.6. The emerging scene

The administered pricing regime has started undergoing some changes. Parallel marketing has now been allowed for kerosene, LPG, LSHS and Lubricants. Private parties are now free to import these products or base stocks and sell them through their own marketing network at prices they consider appropriate. Obviously, such prices will be determined by market forces without any directive of the Government. Import of Naphtha and Jet Fuel for own use by the importers has been decanalised.

The ownership pattern in the oil sector is also changing. Parallel marketing has brought in new marketing companies in the private sector. New refining capacities are also being set up by private parties on their own or jointly with public sector oil companies. A number of companies have been given contracts for development of new oil and gas fields. Similarly, production sharing exploration contracts have been signed with private companies.

With the change in the structure of the oil industry and the new steps that have been taken, it is very likely that the regime of administered pricing will undergo significant changes in the coming years. However, such changes will be preceded by a very

detailed examination by the Government of the implications of these changes for the consumer price levels as also for different activities in the oil sector.

3.3. ENVIRONMENTAL ISSUES

3.3.1. Organisational structure in the environment sector

The institutional framework for environmental management in India was initiated when the National Committee on Environmental Planning and Coordination was set up in 1972 in the context of the Stockholm Conference. Based on the recommendations put forth in the Tiwari Committee Report, a Department of Environment was created in 1980. The function of the Department was to:

- act as a nodal agency for environmental protection,
- carry out environment appraisals of development projects, and
- have administrative responsibilities for pollution monitoring and regulations.

The functions hitherto performed by the Science and Technology Ministry were transferred to this newly created department. Later in 1985, the subjects of forests and wildlife were also brought together and a Ministry of Environment and Forests (MoEF) was created. A National Committee of Environmental Planning is attached to the Ministry in an advisory role.

There are several organisations supporting the MoEF such as, the Central Pollution Control Board (CPCB), the Botanical Survey of India, the Zoological Survey of India and the Forest Research Institutes, which aid the Ministry in implementation of the Environment Protection Act (EPA), 1986, and primary research areas and environmental conservation/protection.

Almost all the States have also established Environment Departments and Pollution Control Boards, which undertake pollution control and monitoring environmental protection programmes.

3.3.2. Environmental legislation in India

3.3.2.1. Constitutional provisions

For the first 30 or years so of independent India, there was no mention or interpretation of environmental concerns in the Constitution. In 1976, Parliament passed the Constitution (42nd Amendment) Act. Part IV of this Act deals with the directive principles of State policies; Article 47 says: " the State shall regard the raising of the level of nutrition and the standard of living of its people and the improvements of public health as among its primary duties......" This article provides for the improvement of public health as one of the primary duties of the State and it

could very well include by implication, the protection and improvement of the environment, for, the control and prevention of environmental pollution necessarily and primarily comes within the concept of the improvements of the Act. Section 10 of this 42nd Amendment Act says: "After Article 48 of the Constitution the following Article shall be inserted, namely - Protection and improvement of environment and safeguarding of forests and wildlife - The State shall endeavour to protect and improve the environment and to safeguard the forests and the wildlife of the country."

Protection of the environment and promotion of ecological aspects has been included as the Twelfth Schedule to the Constitution which was added by the Constitution (74th Amendment) Act, 1992. This Amendment Act was passed in lieu of democratic decentralisation.

3.3.2.2. Legal framework

With the backdrop of environmental duties of every citizen expressed in the Constitution, a legal framework is essential to ensure that the constitutional requirements are abided. A strong legislative framework is also required if India's directional development is to be sustained. There are several specific and general Acts/Rules/Laws that have been in effect since before Independence.

The major environment-related legislations are given in References. The EPA of 1986 is an umbrella legislation for protecting environment in the country and some of the major inclusions in the EPA, 1986 are detailed later. The Government of India (GOI) has issued strict guidelines, requiring the industries to obtain no objection certificate (NOC) from the concerned State Pollution Control Boards (SPCBs), before a letter of intent (LOI) is converted into an industrial license. While the Ministry of Environment and Forests (MoEF) is the nodal agency for the implementation of pollution-related provisions of the Environment Protection Act 1986, the CPCB and SPCBs are statutory authorities entrusted with the responsibility of implementing the Water and Air Pollution Control Act. Also, several other enactment powers which have been delegated to the authorities from time to time.

CPCB has been vested with powers to take over the functions of the SPCBs in specific cases, in the event of inaction despite specific directions. The CPCB, being the authority for implementing policies formulated by the MoEF, also has the powers to frame implementation strategies for pollution control, the most important of which is the development of the minimal national standards (MINAS). The ambient air

quality standards were revised recently and the new ambient air quality standards, which came into enforcement from May 1994, are given in Table 3.6.

Table 3.6: New ambient air quality standards (May 1994)

Pollutant	**Averaging time**	**Industrial**	**Types of areas** **Residential**	**Sensitive**
Sulphur dioxide (SO_2)	Annual average*	80 μg/m^3	60 μg/m^3	15 μg/m^3
	24 hours **	120 μg/m^3	80 μg/m^3	30 μg/m^3
Oxides of nitrogen as NO_x	Annual average*	80 μg/m^3	60 μg/m^3	15 μg/m^3
	24 hours **	120 μg/m^3	80 μg/m^3	30 μg/m^3
Suspended particulate matter	Annual average*	360 μg/m^3	140 μg/m^3	70 μg/m^3
	24 hours **	500 μg/m^3	200 μg/m^3	100 μg/m^3
Respirable particulate matter (size less than 10 μm)	Annual average*	120 μg/m^3	60 μg/m^3	50 μg/m^3
	24 hours **	150 μg/m^3	100 μg/m^3	75 μg/m^3
Lead	Annual average*	1.0 μg/m^3	0.75 μg/m^3	0.50 μg/m^3
	24 hours **	1.5 μg/m^3	1.00 μg/m^3	0.75 μg/m^3
Carbon monoxide	8 hours **	5.0 mg/m^3	2.0 mg/m^3	1.0 mg/m^3
	1 hour	10.0 mg/m^3	4.0 mg/m^3	2.0 mg/m^3

*Annual arithmetic mean of minimum 104 measurements in a year taken twice a week, 24 hourly, at uniform interval.

**24 hourly/ 8 hourly values should be met 98% of the time in a year. However, 2 per cent of the time, it may exceed, but not on two consecutive days.

Notes:

1. National ambient air quality standard: The levels of air quality necessary with an adequate margin of safety, to protect public health, vegetation and property
2. Whenever and wherever two consecutive values exceeds the limit specified above for the respective category, it would be considered adequate reason to institute regular/continuous monitoring and further investigations
3. The State government/State Board shall notify sensitive and other areas in the respective states within a period of six months from the date of notification of National Ambient Air Quality Standards

Source: Central Pollution Control Board, New Delhi (1994)

In order to maintain the ambient air quality at the desirable level, one of the responsibilities of the Central Pollution Control Board (CPCB) is to evolve emission regulations for air-polluting industries under Section 54 of the Air Act, 1981 to control air pollution at source. Emission standards for 12 out of 20 such industries, have been developed.

The primary aim of the ambient air quality standards is to provide a basis for protecting public health from the adverse effects of air pollution and for eliminating, or reducing to a minimum, the air pollutants that are hazardous to human health and well being. Ambient air quality standards (both short-term, i.e. 24 hourly, and long-term, i.e. annual) have been laid down for industrial, residential, and sensitive areas in respect of various pollutants like SO_2, NO_X, SPM, RPM, pH and CO.

An effective air pollution control program needs data on the existing ambient air quality based on which a control strategy can be planned. The Central Pollution Control Board (CPCB) launched the National Ambient Air Quality Monitoring (NAAQM) in 28 stations spread over seven cities in 1984. Presently, 290 stations spread over 92 cities and towns have been established. Prior to the launch of NAAQM in 1984, the National Environmental Engineering Research Institute (NEERI) was monitoring air quality in ten major cities in the country, since 1978. NEERI continues to monitor air quality in these cities. In addition, CPCB and SPCB are monitoring air quality in other stations. The data collected from the stations are regularly analysed by NEERI and CPCB. It has been observed that at a majority of the monitoring stations, the concentration of SPM is more than the prescribed annual ambient air quality standards for residential areas, i.e. 140 $\mu g/m^3$. In case of NO_X and SO_2, the values were observed to be below the annual average for residential areas. Therefore it can be concluded that the combustion of domestic or imported coal meet the ambient air quality standards for SO_2 without FGD. It is important to note though, that all new coal fired plants of 200 MW and above installed capacity, are leaving the requisite space necessary to install FGD in future, if the need arises.

3.3.2.3. References

A list of publications is given underneath for detailed information on the above issues. Publications which are of special interest with regard to this study are:

Water pollution:

- The River Boards Act, 1956
- The Water (Prevention and Control of Pollution) Act, 1974
- The Water (Prevention and Control of Pollution) Cess, 1977

Air pollution:
- The Mines and Minerals (Regulation and Development) Act, 1947
- The Industries (Development and Regulation) Act, 1951
- The Air (Prevention and Control of Pollution) Act, 1981

Others:
- The Indian Forest Act, 1927
- The Wildlife (Protection) Act, 1972
- The Urban Land (Ceiling and Regulation) Act, 1976
- Forest Conservation Act (1980)

Recent legislation:
- The Environment (Protection) Act, 1986
- The Public Liability Insurance Act (PLI), 1991
- The Gazette Notification on environmental audit issued in March 1992 has been amended
- Amendments to manufacture, storage and import of Hazardous Chemical Rules have been finalised
- Amendments to Hazardous Waste (Management and Handling) Rules, 1989 have also been finalised
- A Notification regarding authorisation of various agencies under Sections 13 and 18 of the PLI Act has been issued
- A fresh Coastal Zone Regulation Notification containing certain amendments has been issued and suggestions from the public have been invited

3.3.2.4. *Environment (Protection) Act, 1986*

Since the enactment of the EPA 1986, many steps have been taken by the MoEF to provide the legal and institutional basis which include framing of rules, notification of standards, delegation of powers, identification of agencies for hazardous chemicals management and setting up of environmental protection councils in the States. The EPA is an umbrella legislation and some of the major inclusions in the EPA, 1986 are detailed as:

- The rules under the Water and Air Act have been amended and as per these amendments, the consent order issued by the respective SPCBs to the industries would be valid for a period of 15 years or till such time as there is some significant change in the process-whichever is earlier. No conditional consent would be issued by the SPCBs without complete installation of the required pollution control equipment.

- The Gazette Notification on environmental audit issued on 12th March, 1992 has been amended vide Notification GSR 386 (E) dated the 22nd April, 1993. The Notification applies to all the units seeking consent under the Water Act, 1974, or Air Act 1981 or authorisation under the Hazardous Wastes (Management and Handling) Rules, 1989. Beginning from 1993, all units are required to submit environmental statements for the period ending 31st March on or before 30th September every year to the concerned SPCBs.
- A Bill to provide assistance for the setting up of national environment tribunals and expeditious disposal of cases regarding payment of compensation to the victims of accidents occurring while handling hazardous substances was introduced in Parliament in August, 1992.
- Amendments to Manufacture, Storage and Import of Hazardous Chemicals Rules have been finalised. Safety audit in major accident hazard units will now become mandatory with the notification of these Rules.
- Rules for classification, labelling and packaging of hazardous chemicals are being finalised.
- Amendments to Hazardous Waste (Management and Handling) Rules, 1989 have been finalised and are being notified.
- The Forest (Conservation) Rules, 1981 have been amended to further decentralise and streamline the examination of proposals received under the Forest Conservation Act, 1980.
- The Indian Forest Act, 1927 is proposed to be revised and a draft of the revised legislation has been circulated among the State Governments for their comments.
- Emission standards for various polluting industries have been notified under the EPA, 1986.

3.3.2.5. Environmental Impact Assessment (EIA)

In India, Environment Impact Assessment (EIA) was made mandatory and in January 1994 (amended in May 1994) under the EPA for 29 specified activities falling under various sectors such as industries, mining, irrigation, power, transport, tourism, etc. According to the Act, a person who desires to undertake any new industry or project shall submit an application to the Ministry of Environment and Forests along with an EIA report, which will be evaluated and assessed by an Environmental Appraisal Committee. The notification stipulates, inter alia, that all applications complete in every material respect, have to be examined and decision conveyed to the applicants within 30 days in respect of site clearance and 120 days in respect of projects.

3.3.3. List of projects requiring environmental clearance

The projects which are of particular interest are:

- Ports, harbours, airports (except minor ports and harbours).
- Petroleum refineries including crude and product pipelines.
- Exploration for oil and gas and their production, transportation and storage.
- Thermal power plants.
- Mining projects (major minerals) with leases more than 5 hectares.

3.3.4. Oil and gas sector issues

3.3.4.1. Crude exploration and production

In the production of crude oil, the principal wastes can be categorised as those arising from drilling and those from production *per se*. The former are of lesser concern, being the drilling muds, additives, cements, well-treating fluids, and flow enhancers for stimulating production. The main waste from production is the brine associated with the oil/gas in the crude-bearing formation or reservoir. It is mostly water with dissolved mineral salts, which also contains dissolved petroleum in small concentrations. After a phase separation at the lease, the brine may be pumped back into the reservoir at points which do not affect production.

3.3.4.2. Crude transportation

In the transport of crude by truck, rail, barge, tanker or pipeline there is a build-up of bottom sediment waste (BSW), which must sooner or later be discharged somewhere. There is also the serious and much-publicised catastrophic probability of oceanic spills. The threat to the marine ecosystem from these cannot be overstated, so much so that sometimes large colonies of fish, and even coral reefs are wiped out. Absorption of large quantities of oil also makes the fish unsafe for human consumption.

3.3.4.3. Natural gas

Oil in the reservoir contains various proportions of associated or dissolved gas. Natural gas is used primarily as a feedstock for the fertiliser industry and also as fuel for industry or power generation. The rest of the gas is let off at the tail-end as a flare. About 6.4 % out of a total gross production of about 10.91 Bcu.m of natural gas in April-September 1995 was flared. Flaring of natural gas has adverse impacts in terms of air pollution in the form of emissions of oxides of sulphur and nitrogen; and carbon dioxide, an important greenhouse gas.

3.3.4.4. Refineries

Pollution control/environmental protection is considered to be an integral part of the refining operations in the country. In recent times, especially after the enactment of the Environment Protection Act in 1986, statutory requirements have become stricter, and accordingly, the refining sector has been gearing itself towards the upgradation of existing treatment systems/control techniques and monitoring facilities. MINAS for liquid effluents, and air-emission standards have been evolved by the CPCB for major categories of water and air polluting industries, including oil refineries. These refer to the maximum concentration of pollutants in effluents discharged into a water body or emissions that may be discharged into the atmosphere. The emission standards for oil refineries are shown in Table 3.7.

Table 3.7: Emission standards for oil refineries

• Parameter	Quality	Quantity (kg/1000t of crude processed)
MINAS for refinery waste waters		
Basis: Waste-water generation - 700 kilo litre/1000 t crude processed		
• Oil and grease (mg/l)	10.00	7.00
• Total suspended solids (mg/l)	20.00	14.00
• BOD @ 20 °C (mg/l)	15.00	10.50
• Phenols (mg/l)	1.00	0.70
• Sulphides (mg/l)	0.50	0.35
• pH	should be between	6.0-8.5
Air pollution emissions standard (under EP Act - 1986)		
		Emissions Sulphur dioxide
• Crude distillation (atmospheric plus vacuum) (kg/t of feed)		0.25
• Catalytic cracker (kg/t of feed)		2.50
• Sulphur recovery unit (kg/t of sulphur in feed)		120.00

With a view to secure nationwide compliance with these prescribed standards, task forces have been constituted by the CPCB for major categories of industries. The status of pollution control in the refining industry, as emerging from the deliberations of task forces, is provided below:

• total number of oil refineries in the country	13
• number of units complying with both MINAS and air emission standards	01
• number of units complying with MINAS	05
• number of units complying with air emission standards	03

Along with the control and monitoring of emissions from refineries, ambient air quality monitoring in and around refinery locations is regularly carried out in all the

hydro projects on the ecology of the region. Keeping this in mind, it is to be expected that large hydro-electric projects will face increasing hostility from the local population as well as environmental groups.

As regards the coal-fired thermal power stations, India has not witnessed any widespread or major protests against them yet, mainly because they do not involve mass relocation of the local populace as in the case of hydro-electric projects. Though Indian coal is low in sulphur content, its ash content is almost 50%, and it also has a low calorific value as compared to imported coal.

There is a proposal before the central government to make it mandatory for new thermal power stations to use washed coal whenever the coal needs to be transported beyond a distance of 500 km from the mines. This makes sense, as the rail transportation charges for coal for a distance of 500 km are almost equal to the pit-head price (see Table 3.2). Washing the coal would reduce its weight to almost half, and also mitigate the ash handling problems at the power stations.

Imported coal is low in ash content, and though it has a higher calorific value than Indian coal, is high in sulphur content. Though SO_X emissions do not figure high on the list of environmental activists in India at the moment, this could change over the next few years.

CHAPTER 4
POWER GENERATION

All the three states suffer from power shortages. Karnataka is the worst affected, having a shortfall of over 3000 GWh in 1993-94. The shortages are expected to disappear in all the states by the year 2000, with the addition of new generating stations. As per the current proposals, Karnataka will experience a shortfall of nearly 400 MW in 2015 in the case of the high growth scenario, but the other two states have a comfortable surplus, and could export power to Karnataka. The lower limit of the sales potential for natural gas is the maximum in Tamil Nadu, reaching over 3500 million cubic meters per year by 2015. The upper limit is again highest in Tamil Nadu at nearly 6000 million cubic meters per year in 2015. The imputed value for natural gas at various sites was calculated, and it was found that the lowest value at $ 4.56/MMBtu was in the case of an indegenous coal based power station located at Madras, while the highest value was $ 6.95/MMBtu for a plant using imported coal and located in Coimbatore. Most of the imputed values were found to be above $ 5.00/MMBtu. On conducting the sensitivity analysis, the imputed value varied between 7.49 $/MMBtu to 4.51 $/MMBtu.

4.1. OVERVIEW OF THE STATE ELECTRICITY BOARDS

4.1.1. Current electricity supply position

Karnataka, Kerala and Tamil Nadu, are all facing power shortages to varying degrees. In Karnataka and Kerala, the situation deteriorated from 1990-91 to 1992-93, but improved somewhat in 1993-94 (see Table 4.1). In the case of Tamil Nadu, the situation improved over the former period, but took a turn for the worse in 1993-94.

Table 4.1: Electricity supply position

(%)

	Deficit in electricity requirement			
State	**1990-91**	**1991-92**	**1992-93**	**1993-94**
Karnataka	22.9	23.6	25.9	21.9
Kerala	0.5	3.3	3.7	1.9
Tamil Nadu	6.4	4.8	1.8	3.9

Source: Annual report on the working of state electricity boards and electricity departments, Planning Commission, Government of India, October 1995

In absolute terms, the deficit in 1993-94 for Karnataka, Kerala and Tamil Nadu, works out to be 3076 GWh, 119 GWh and 791 GWh respectively.

4.1.2. Current power generating capacities

4.1.2.1. Karnataka Electricity Board

Karnataka Electricity Board (KEB), unlike other electricity boards, purchases most of its electricity requirements from other power producing organisations, having under its ownership a few small hydro stations amounting to a total installed capacity of less than 350 MW, and a gas oil based generating station of capacity 128 MW. This translates to about 10% of the installed generating capacity in the state.

The remaining capacity is owned by Karnataka Power Corporation (KPC), a state government owned company, which sells all the power it generates to KEB on an exclusive basis. Table 4.2 lists the existing power stations in Karnataka by ownership.

Table 4.2: Particulars of Generating Stations and by KEB & KPC (1994-95)

No.	Generation Station	Capacity (MW)	Generation (GWh)		Owned by
			1993-94	1994-95	
1	Shri K. Seshadri Iyer, Hydro Electric Station	42.00	91.00	101.40	KEB
2	Shimsha Hydro Electric Power Station	17.20	96.00	89.50	KEB
3	Mahatma Gandhi Hydro Power Station, Jog	120.00	492.00	503.60	KEB
4	Munirabad Power House, Munirabad	27.00	93.00	90.60	KEB
5	Tungabhadra Dam Power House	14.40	39.00	41.40	KEB
6	Yelahanka Gas Oil Generating Station	127.80	147.00	364.60	KEB
7	Sharavathy Hydro Electric Power Station, Jog	1006.20	4828.00	5571.80	KPC
8	Bhadra Hydro Electric Power Station	33.20	39.00	58.70	KPC
9	Linganamakki Dam Power House, Jog	55.00	276.00	330.80	KPC
10	Nagjhari Power House, Dandeli	810 00	2613.00	3707.00	KPC
11	Supa Dam Power House	100.00	502.00	644.30	KPC
12	Varahi Power House	230.00	1216.00	1340.30	KPC
13	Ghataprabha	32.00	125.00	151.90	KPC
14	Mani	9.00	28.00	37.40	KPC
15	Kalamala	0.40	0.80	0.40	KPC
16	Sirwar	1.00	0.40	1.30	KPC
17	Ganekal	0.35	0.04	0.03	KPC
18	Mallapur	4.50	1.70	12.60	KPC
19	Raichur Thermal Power Station	840.00	3697.00	3696.00	KPC
	Total	**3470.00**	**14284.94**	**16743.63**	

Note:	Capacity:	KEB Owned	348.40 MW
		KPC Owned	3121.85 MW

Besides availing of power supply form KPC, KEB also purchases power from power stations owned by the Central government corporations. These stations are Ramagundam of National Thermal Power Corporation (NTPC) in Andhra Pradesh (coal based), Neyveli of Neyveli Lignite Corporation (NLC) in Tamil Nadu (lignite fired) and Kalapakkam of Nuclear Power Corporation (NPC) at Madras in Tamil Nadu (Nuclear). The total share of Karnataka from these stations amounts to 563 MW.

4.1.2.2. Kerala State Electricity Board

All the generating capacity owned by Kerala State Electricity Board (KSEB) is hydro based. Like Karnataka, Kerala is also entitled to a share of the power generated from Ramagundam, Neyveli and Kalpakkam power stations owned by Central government corporations. This share amounts to a total of 480 MW. The details of the stations owned by KSEB are given in Table 4.3.

Table 4.3: Power stations owned by KSEB

Power Station	Installed Capacity (MW)
1. Pallivasal	37.50
2. Sengulam	48.00
3. Poringalkuthu	32.00
4. Neriamangalam	45.00
5. Panniar	30.00
6. Sabarigiri	300.00
7. Sholayar	54.00
8. Kuttiyadi	75.00
9. Idukki	780.00
10.Idamalayar	75.00
Total	**1476.50**

4.1.2.3. Tamil Nadu Electricity Board

Tamil Nadu Electricity Board (TNEB) was formed in 1957 under the Central Electricity (Supply) Act of 1948. The Board owns and operates 26 small hydro stations, four large coal-fired stations, some wind mill farms, and a small gas turbine station. In addition, the state is also entitled to a share of power (1840 MW) from the Central sector owned stations. The particulars of the stations owned by TNEB are shown in Table 4.4.

Table 4.4: Installed capacity of TNEB

Name of power station	Installed Capacity (MW)	Plant Load Factor (%)
Hydro		
Pykara	70	62
Moyar	36	48
Kundah-I	60	50
Kundah-II	175	44
Kundah-III	180	25
Kundah-IV	100	23
Kundah-V	40	23
Aliyar	60	40
Suruliyar	35	32
Kadamparai	400	5
Pykara Mini	2	40
Mettur Dam	40	43
Mettur Tunnel	200	43
Papanasam	28	59
Periyar	140	48
Sarkarpathy	30	61
Sholayar-I	70	56
Sholayar-II	25	32
Kodayar-I	60	57
Kodayar-II	40	29
Servalar	20	26
Lower Mettur	120	44
Vaigai Small	6	51
Lower Bhavani Small	8	64
Punachi Mini	2	6
Maravakandi Mini	0.75	15
Coal		
Ennore	450	55
Tuticorin	1050	68
Mettur	840	76
North Madras	420	NA
Gas	10	16
Wind	20	NA
Total	**4738**	-

'NA' indicates that the data is not available.

4.1.3. Transmission and distribution systems

4.1.3.1. Karnataka Electricity Board

The details of length of transmission lines and sub-stations owned by KEB is given in Table 4.5.

Table 4.5: Particulars of transmission & distribution network

Voltage level (kV)	Circuit KM	Sub-stations	Total Transformer capacity (MVA)
400*	910	1	500
220	6295	25	5109
110	5156	85	2540
66	4628	162	2858
33	5175	181	1228
TOTAL	**22165**	**454**	**12234**

11/13.2/4.6/2.3 kV - 1,11,867
LT 230/400 V - 3,10,671
* Charged at 220 V

Efforts are being made to establish sub-stations at load centres, reconductoring feeders by higher sizes, increasing voltage levels, installation of capacitor banks, and strengthening transmission and distribution network on the basis of detailed system improvement studies.

During last several years, much attention has been paid to improve T&D network aimed at reducing system losses.

Table 4.6: Line Losses

(%)

Year	1991-92	1992-93	1993-94	1994-95
Line Losses	18.91	18.70	18.60	18.60

It is observed that the line losses are showing a declining trend. The figures indicated as line losses are more an estimation since the actual energy consumed by irrigation pumpsets (which is the largest category with consumption of about 46% of the total) is not measured as energy supplies are free (prior to revision of tariffs on July 1, 1996), but a computed figure is used to estimate consumption. The accuracy of system loss figure therefore depends on the reliability of estimates made for consumption figures for irrigation pumpsets.

4.1.3.2. Kerala State Electricity Board

Brief particulars of the transmission systems of KSEB are given in Table 3.16 below.

Table 4.7: Transmission lines & sub-stations of KSEB

Voltage	Line length (circuit km)	Sub-stations
220 kV	1068	5
110 kV	2210	38
66 kV	2624	103

In 1993-94, about 65 percent of the available power was consumed by about 4.2 million low tension power users. Supplies to low tension, low density consumers entail larger system losses. However the number of agricultural pumpsets supplies which involve very large line loss are very small in the KSEB system.

The high tension supply accounts for about 35 percent distributed among 1149 consumers.

The position of system losses over three years is presented in Table 4.8.

Table 4.8: System losses of KSEB

(%)

Year	1991-92	1992-93	1993-94
System loss	22	21	20

While the system losses are very high particularly considering that the state covers a small geographic area and the task of electrification of village and irrigation pumpsets is small, the trend is favourable as the percentage losses are declining year after year.

4.1.3.3. Tamil Nadu Electricity Board

The Tamil Nadu Electricity Board has an extensive transmission and distribution network. The main transmission network comprise - 230 kV, 110 kV and 66 kV lines and sub-transmission network comprise 33 kV, 22 kV and 11 kV lines. Some basic data regarding the network is indicated in Table 4.9.

Table 4.9: Transmission & distribution network of TNEB

Voltage	Single Circuit km	Double Circuit km	No of Sub-stations	No. of Transformers
400 kV	-	-	2	6
230 kV	4090	711	21	53
110 kV	5700	2073	271	541
66 kV	1750	310	67	133
33 kV	14634	3923	264	462
22 KV	28895	5	5	7
11 KV	67018	-	-	-
LT.	377247	-	-	104327

Total No of Consumers	10.2 million
No. of Villages electrified	63,052
Tribal colonies electrified	26,713
Irrigation pumpsets electrified	1.29 million

The above system network provides service to over 10 million consumers, including about 1.3 million irrigation pumpsets and about 90 thousand villages and rural colonies (tribal colonies).

Of the 23093 GWh sold during the year, as much as 13965 GWh were sold to low tension consumers and the remaining 9128 GWh to high tension consumers. Nearly half of low tension supplies were to irrigation pumpsets.

Table 4.10 shows the gradually declining system losses of TNEB over the past few years.

Table 4.10: System losses of TNEB

(%)

Year	1990-91	1991-92	1992-93	1993-94	1994-95
System loss	18.40	18.35	17.50	17.25	17.00

While the system loss is showing a declining trend, this is more an estimation. The electricity supply to irrigation pumpsets which accounts for more than 27% of

consumption is free and hence not measured, but a computed figure is used to estimate consumption. Hence the accuracy of system loss figures wholly depends on the reliability of estimates worked out for energy consumption of irrigation pumpsets.

4.1.4. Financial positions of the electricity boards

4.1.4.1. Karnataka Electricity Board

The board generates operating surplus in most of the years. The income-expenditure picture for the year 1994-95 is presented in Table 4.11.

Table 4.11: Revenue Account of KEB for 1994-95

Sl. No.	Particulars		Rs in millions
I	**INCOME**		
	1) Revenue from sale of power		16720.7
	2) Miscellaneous Revenue		837.3
	3) Others (R.E. Subsidy)		2063.7
	4) Other Subsidy/Grants		1.6
		Total-I	**19623.3**
II	**EXPENDITURE**		
	1) Fuel		532.4
	2) Cost of Power Purchase		10742.5
	3) Establishment Expenses		3586.5
	4) Operation & Maintenance		820.4
	5) Depreciation		1539.5
	6) Prior Period Expenses/Others		183.0
	7) Interest on Loans		
	I) Government		486.2
	ii) Others		1375.5
		Total - II	**1926.6**
		Surplus	**357.3**

While the board is generating a surplus, it is facing very severe resource constraints for making investments on new and improvement projects.

4.1.4.2. Kerala State Electricity Board

A summary of the financial position of the Board for three years is presented in Table 4.12.

Table 4.12: Financial summary for three years for KSEB

(Million rupees)

Sl. No.	Particulars	1991-92	1992-93	1993-94
1	Revenue Receipts	3417.05	4446.25	5377.36
	Subsidies	15.65	0.18	-
	Total	3432.70	4446.43	5377.36
2	Revenue expenditure (excluding depreciation and institution loan and including other debits and extra ordinary items).	3237.41	3059.98	4370.08
	Net	195.29	1386.46	1007.29
	Add other expenses capitalised	309.70	295.98	445.69
	" Net prior (Debit)/Credit (-)	29.61(-)	381.75	153.95
3	Gross Surplus (1-2)	475.39	1300.69	1606.93
4	Utilisation			
	a Depreciation	226 89	279.23	390.93
	b. Interest and finance charges	1049.81	1378.89	1520.84
	Less			
	Capitalised	444.40	541.62	545.99
	Net interest	605.40	837.27	974.86
		832.29	1116.50	1365.77
5	Net Surplus/Deficit (3-4)	(356.91)	184.19	241.15
6	Total returns on capital employed (Net surplus + Net interest)			
		1991-92	1992-93	1993-94
	Net Surplus	(356.91)	184.19	241.15
	Net interest	605.40	837.27	974.86
7	Capital employed	5400.31	6525.73	7609.77
	Percentage of return on capital employed	4.60%	15.65%	15.98%
	Capital invested	10952.56	11600.47	13052.12
	Percentage of return on capital invested	2.27%	8.81%	9.32%

The Board is generating significant surplus and the rate of returns on net fixed assets works out to much more than the prescribed three percent.

4.1.4.3. Tamil Nadu Electricity Board

A summary of financial analysis of TNEB for two years -1993-94 & 1994-95 is given in Table 4.13.

Table 4.13: Financial summary for TNEB

(Million rupees)

Particulars	1993-94	1994-95
INCOME		
1. Revenue from Sale of power	26035.4	34687.7
4. Subsidies & Grants	5271.0	3500.6
5. Other Income	308.1	395.2
Total Income "A"	31614.5	38583.5
EXPENDITURE		
6. Purchase of power	6605.2	8229.6
7. Generation of power	12366.4	13773.3
8. Repairs & Maintenance	846.3	1067.7
9. Employee Costs	5215.8	6360.8
10. Admn. & Genl. Expenses	947.4	1131.3
11. Depreciation & Other related	1369.6	1758.0
debits	4168.3	4452.0
12. Interest and Finance charges		
Sub-total "B"	31519.0	36772.7
Less: Expenses capitalised:		
13 Interest & Finance Charges Capitalised	1165.3	1047.0
14. Other expenses Capitalised	1044.0	1184.6
Total Expenses Capitalised "C"	2209.3	2231.6
Sub Total (B) - (C)	29309.7	34541.1
15. Other Debits	151.1	170.8
16. Extra Ordinary Items	39.1	1.9
	190.2	172.7
Total (D)	29499.9	34713.8
Profit before tax (A)-(D)	2114.6	3869.7
Net Fixed Assets (beginning of the year)	38888.3	42790.9
Rate of return	7.26%	9.37%

The board is generating significant surplus throughout. While SEBs are expected as per central government guidelines to earn a rate of return of 3% on the net fixed assets at the beginning of the year, TNEB is actually generating nearly 3 times that, in spite of providing free power to agricultural pumps and lighting for huts.

4.1.5. Financial position of the states

Tables 4.14 to 4.17 give information related to the financial position of the states.

Table 4.14: Revenue receipts (1995-96)

(Rs million)

	KARNATAKA	KERALA	TAMIL NADU
TOTAL REVENUES	88799.7	48775.1	89850.7
Tax Revenue	65554.6	38914.4	74991.3
A.State's own Tax Revenue	51159.5	28590.8	56943.5
1. Taxes on Income	1240	270.1	147
2. Taxes on Property and Capital transactions	4350	2847.6	4387.5
3.Taxes on commodities and services	45569.5	25473.1	52409
B. Share in Central Taxes	14395.1	10323.6	18047.8
Non-Tax Revenue	23245.1	9860.7	14859.4
C. State's own Non-Tax Revenue	11225.3	3724.9	5963.9
1.Social Services	1114.6	466.5	864.2
2. Fiscal Services	0	0	0
3. Economic Services	3444.8	1839.3	2230
D. Grants from the Centre	12019.8	6135.8	8895.5

Table 4.15. Revenue expenditure (1995-96)

(Rs million)

	KARNATAKA	KERALA	TAMIL NADU
TOTAL EXPENDITURE	90936.3	58611.9	100606.1
1. Developmental Expenditure	61671.5	35693.6	67290.5
A. Social Services	34325.4	24580	41745.6
B. Economic Services	27346.1	11113.6	25544.9
2. Non-Developmental Expenditure	27727.9	22168.3	31511.1
3. Compensation and Assignments to Local Bodies and Panchayati Raj Institutions	1536.9	750	1804.5

Table 4.16: Capital receipts (1995-96)

(Rs million)

	KARNATAKA	KERALA	TAMIL NADU
TOTAL RECEIPTS	18098.4	17150.7	25014.9
1. Internal Debt	2886.5	4551.4	4514.3
2. Loans and Advances from the Centre	10528	8180.4	15566
3. Recovery of Loans and Advances	1233.1	265.6	1183.6
4. Inter-State Settlements	0	0	0
5. Contingency Fund	-50	0	0
6. Small Savings, Provident Funds etc. (net)	2470	3801.5	1904.7
7. Reserve Funds (net)	1030.8	6.3	894.5
8. Deposits and Advances(net)	0	415.8	622.9
9. Suspense and Miscellaneous (net)	0	-32.5	-55.7
10. Appropriation to Contingency Fund (net)	0	0	0
11. Miscellaneous Capital Receipts	0	0	0
12. Remittances (net)	0	-37.8	384.6

Table 4.17: Capital disbursements (1995-96)

(Rs million)

	KARNATAKA	KERALA	TAMIL NADU
TOTAL DISBURSEMENTS	17978	9373.7	15773.3
1. Total Capital Outlay	11829.7	5004	5351.6
(a) Developmental	11529.5	4761.5	4846
(i) Social services	1117	514.9	1416.9
(ii) Economic Services	10412.5	4246.6	3429.1
2. Discharge of Internal Debt	492.1	210.9	202.7
3. Repayment of Loans to the Centre	2100.1	1491.3	2522.9
4. Loans and Advances by State Governments	3556.1	2667.5	7696.1
(a) Developmental Purposes	3372	2613.9	7221.9
1. Social Services	1136.1	822.3	3341.3
2. Economic Services	2235.9	1791.6	3880.6
(b) Non-Developmental Purposes	184.1	53.6	474.2
A. Surplus / Deficit on Capital Account	120.4	7777	9241.6
B. Surplus / Deficit on Revenue Account	-2136.6	-9836.8	-10755.4
C. Overall Surplus / Deficit (A+B) Financing of Surplus / Deficit	-2016.2	-2059.8	-1513.8
D. Increase / Decrease in Cash Balance	-2516.2	-2099.8	-1514
E. Withdrawals from / Additions to Cash Balance Investment Account	500	40	0.2

4.2. ELECTRICITY DEMAND AND SUPPLY PROJECTIONS

Table 4.18 shows the projected electricity demand for the high and low growth scenarios respectively for the three states, and the consequent installed capacity requirements. The methodology for the demand projections as well as the installed capacity requirements is discussed in detail in Chapter 2.

Table 4.18: Total electricity required and consequent installed capacity

	Total energy required (GWh)		**Installed capacity reqd. (MW)**	
Year	**High growth**	**Low growth**	**High growth**	**Low growth**
Karnataka				
2000	19643	19588	5469	5454
2005	25463	24946	6921	6781
2010	33299	31165	8842	8275
2015	42886	38209	11388	10146
Kerala				
2000	8470	8401	2387	2368
2005	11518	10874	3168	2991
2010	16798	14139	4513	3798
2015	24009	18183	6450	4885
Tamil Nadu				
2000	24862	24722	6718	6681
2005	32038	30725	8458	8112
2010	43787	38364	11429	10013
2015	59434	47550	15513	12411

Table 4.19 shows the fuel-mix of the installed capacities.

The plant-wise break-up of the new capacities and the expected period of commissioning is given in Appendices 2.1, 2.2 and 2.3 for Karnataka, Kerala and Tamil Nadu respectively.

Table 4.19: Fuel-mix of installed capacities till year 2015

(MW)

	Hydro	Coal/ Lignite*	Gas Oil	Nuclear*	Fuel Oil	Gas	Vacuum Residue	Naphtha	Wind	Total
Karnataka										
1995	2502	1373	128	30	0	0	0	0	0	4033
	62%	34%	3%	1%	0%	0%	0%	0%	0%	100%
2000	2645	1833	128	140	670	0	0	97	0	5513
	48%	33%	2%	3%	12%	0%	0%	2%	0%	100%
2005	2801	3053	128	250	968	40	0	97	0	7337
	38%	42%	2%	3%	13%	1%	0%	1%	0%	100%
2010	3232	4053	128	360	968	340	0	457	0	9538
	34%	42%	1%	4%	10%	4%	0%	5%	0%	100%
2015	3577	5053	128	470	968	340	0	457	0	10993
	33%	46%	1%	4%	9%	3%	0%	4%	0%	100%
Kerala										
1995	1490	460	0	20	0	0	0	0	0	1970
	76%	23%	0%	1%	0%	0%	0%	0%	0%	100%
2000	1735	660	0	35	0	0	0	0	0	2430
	71%	27%	0%	1%	0%	0%	0%	0%	0%	100%
2005	1745	860	0	50	92	60	500	0	0	3307
	53%	26%	0%	2%	3%	2%	15%	0%	0%	100%
2010	1865	1055	0	65	92	560	500	678	0	4723
	39%	22%	0%	1%	2%	12%	11%	14%	0%	100%
2015	1865	1640	0	80	92	1060	500	1678	0	6915
	27%	24%	0%	1%	1%	15%	7%	24%	0%	100%
Tamil Nadu										
1995	1948	4271	0	330	0	10	0	0	20	6579
	30%	65%	0%	5%	0%	0%	0%	0%	0%	100%
2000	1948	4481	0	360	0	135	0	0	20	6944
	28%	65%	0%	5%	0%	2%	0%	0%	0%	100%
2005	2003	5781	0	390	400	465	0	0	120	9159
	22%	63%	0%	4%	4%	5%	0%	0%	1%	100%
2010	2153	6941	0	420	820	1965	0	0	120	12419
	17%	56%	0%	3%	7%	16%	0%	0%	1%	100%
2015	2153	8901	0	450	820	3465	0	0	120	15909
	14%	56%	0%	3%	5%	22%	0%	0%	1%	100%

* Note. The share of the states from centrally owned stations is included in the coal/lignite and nuclear fuel based power stations

Table 4.20 compares the requirements in installed capacity for the high growth scenario with the capacity expected to be available for the three states. It can be seen that Karnataka is expected to have a shortfall of about 400 MW in the year 2015. The other two states are comfortably placed, and could export their surplus to Karnataka to ease its shortfall.

Table 4.20: Comparison of capacity requirement with expected capacity

(MW)

	Installed capacity required (high growth)	Expected installed capacity	Surplus/Deficit
Karnataka			
2000	5469	5513	44
2005	6921	7337	416
2010	8842	9538	696
2015	11388	10993	(-)395
Kerala			
2000	2387	2430	43
2005	3168	3307	139
2010	4513	4723	210
2015	6450	6915	465
Tamil Nadu			
2000	6718	6944	226
2005	8458	9159	701
2010	11429	12419	990
2015	15513	15909	396

4.3. SALES POTENTIAL OF NATURAL GAS IN THE POWER SECTOR

The gas requirement for a power plant has been taken as 1.04 million cubic meter (MCM) per year for every megawatt of installed capacity, assuming a plant load factor of 68.5% and the calorific value of gas as 8760 kilo calories/Nm^3.

The lower limit for the gas requirement has been derived from the installed capacities of the power stations committed to using gas.

The upper limit for natural gas requirement has been derived as per the following:

1. Since power stations using gas oil, fuel oil or naphtha can switch to using gas without major modifications, it has been assumed that all power stations using these fuels would switch to gas if it was made available at a competitive price.
2. The Ministry of Coal in its IX Plan Document has estimated that only 55% of the coal requirement of the power sector in South India will be met in the year 2001. It has been assumed that this situation of shortages will continue till 2015. To meet the requirements of the balance (coal based) capacities, options would be either imported coal or gas. The planned coal based capacity amenable to a fuel switch would therefore be about 45% of the additions in the period 2005-15 (considering the lead time required to make LNG available). This would amount to 2655 MW (45% of 5900) of capacity which could use natural gas instead of imported coal.

Table 4.21 gives the lower limit of the potential for sale of natural gas in the power sector in Karnataka, Kerala and Tamil Nadu while Table 4.22 shows the estimates of the upper limit.

Table 4.21: Lower limit of natural gas sales potential in power sector

	Gas based capacity (MW)	Gas requirement (MCM/year)[1]
Karnataka		
2000	0	0
2005	40	42
2010	340	354
2015	340	354
Kerala		
2000	0	0
2005	60	62
2010	560	582
2015	1060	1102
Tamil Nadu		
2000	135	140
2005	465	484
2010	1965	2044
2015	3465	3604

Table 4.22: Upper limit of natural gas sales potential in power sector

	Capacity by fuel type (MW)						Gas required (MCM/year)[1]
	Gas oil	Fuel oil	Gas	Naphtha	Coal shortfall	Total	
Karnataka							
2000	128	670	0	97	0	895	931
2005	128	968	40	97	0	1233	1282
2010	128	968	340	457	450	2343	2437
2015	128	968	340	457	900	2793	2905
Kerala							
2000	0	0	0	0	0	0	0
2005	0	92	60	0	0	152	158
2010	0	92	560	678	88	1418	1475
2015	0	92	1060	1678	351	3181	3308
Tamil Nadu							
2000	0	0	135	0	0	135	140
2005	0	400	465	0	0	865	900
2010	0	820	1965	0	522	3307	3439
2015	0	820	3465	0	1404	5689	5917

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[1] Assuming 1520 kcal are required to produce 1 kWh, 68.5% PLF, and clorific value of gas as 8760 kcal/Nm^3.
[(68.5% * 1520 kcal/kWh * 8760 hours/year * 1000 kW/MW) / (8760 kcal/Nm^3 * 1000000 Nm^3/MCM)]
= 1.04 MCM/year per MW.

4.4. TARIFFS

The tariff structure of the three SEBs vary significantly in classification of consumer categories, rate slabs, etc. and direct comparison between the three states will not be consistent. However, the average rate actually realised in respect of different consumer category would provide a fair idea of comparative tariff. This is given in Table 4.23.

Table 4.23: Tariff - average rate realised (1994-95)

(Unit/kWh)

	KEB		KSEB		TNEB	
Category	**Paise**	**Cents**	**Paise**	**Cents**	**Paise**	**Cents**
Domestic	76.90	2.20	57.53	1.64	111.04	3.17
"AEH"	134.60	3.85	-	-	-	-
Commercial	396.70	11.33	117.84	3.37	251.69	7.19
Agriculture	0.00	0.00	29.35	0.84	0.00	0.00
Industries LT	223.20	6.38	101.54	2.90	207.58	5.93
Industries HT	226.10	6.46	90.82	2.59	244.91	7.00
Total	**105.12**	**3.00**	**82.06**	**2.34**	**149.82**	**4.28**

Notes:
1. AEH is All Electric Homes
2. KEB is Karnataka Electricity Board
3. KSEB is Kerala State Electricity Board
4. TNEB is Tamil Nadu State Electricity Board
5. The conversion rate used is Rs 35/ US $

The tariff rate for all categories of consumers except agriculture, is lowest in Kerala. The rates in Karnataka are generally higher than others.

The overall realised rate per unit of power is also the lowest in Kerala and highest in Tamil Nadu.

In spite of generally higher rates in Karnataka for most of the categories, the net average realisation is lower than Tamil Nadu, mainly because 45 percent of power is given to agricultural consumers free of charge.

With effect from July 1, 1996, the tariffs in Karnataka have been revised and now there is a flat tariff of Rs 300.00 per horsepower (HP) on all irrigation pumpsets up to a capacity of 10 HP. Previously, electricity supply to these sets was free. The industrial sector also faces steep tariff hikes with demand charges for high tension consumers being raised from Rs 90/kVA to Rs 140/kVA. Previously HT industries paid energy charges in the range of 150 to 175 paise per kWh, which has now been raised to 270 to 320 paise per kWh.

It is imperative that during the next 2-3 years the tariffs of all three SEBs are raised significantly to meet the high cost of power produced by the new stations (most of them privately owned), and to part finance the investment for creating infrastructure for evacuation of power.

The complete tariff schedules for KEB, KSEB and TNEB are given in Appendices 3.1, 3.2 and 3.3 respectively.

4.5. FUEL COST PASS THROUGH CLAUSE

In general, the power purchase agreements incorporate a fuel cost pass through clause, by which any change in the price of fuel, upward or downward, is passed on to the state electricity board.

However, the Tamil Nadu Electricity Board had issued an advertisement in March 1996, inviting private investors to set up power stations of 30-100 MW capacity using fuel oil and it asked for the cost of electricity as per the following:

> "Cost of Energy: Rupees per kWh on completion date. This cost should remain firm for three years. The promoters are requested to indicate the rate of energy in subsequent three year blocks taking into account the likely variation in fuel cost. This should be given for 15 years, *viz.* 5 blocks. **Under no circumstances escalation in prices during individual blocks will be permitted**. (Emphasis added)"

Apart from this, a fuel cost pass through clause is an almost standard feature of power purchase agreements.

4.6. IMPUTED VALUE FOR NATURAL GAS

4.6.1. Definition

Imputed value or replacement value for natural gas is defined as the value of the gas at which the cost of a unit output in a gas based plant is equal to the cost of unit output in a plant based on alternative fuel/feedstock. When gas is priced at its imputed value, the customer would be indifferent to choices (in terms of cost implications) between gas and the substitute fuel, presently in use.

In the present study, the imputed value for gas for power generation is computed in comparison to substitute fuels such as coal and naphtha for representative sites in Karnataka, Kerala and Tamil Nadu.

The sites selected are Cochin (Kerala), Bangalore, Mangalore and Belgaum (Karnataka) and Madras and Coimbatore (Tamil Nadu). (See map, Figure 4.1). They are important urban centres, are geographically well spread out and cover both port and inland options.

4.6.2. Gas based plants

Table 4.24 lists the various technical and financial parameters considered for arriving at the imputed value.

Table 4.24: Technical and financial parameters for gas based plants

S. No.	Technical Parameters	Units	Values
1.	Plant load factor	%	68.50
2.	Auxiliary consumption	%	3.00
3.	Life of plant	Years	20.00
4.	Calorific value	Kcal/Kg	8760.00
5.	Heat rate	Kcal/kWh	2000.00
6	Fixed operating cost	Rs./kWh	0.15

S. No.	Financial Parameters	Units	Values
1.	Discount rate	%	12
2.	Capital cost per MW	Rs. million	24.5
3.	Investment period	Years	3

4.6.3. Coal based plants

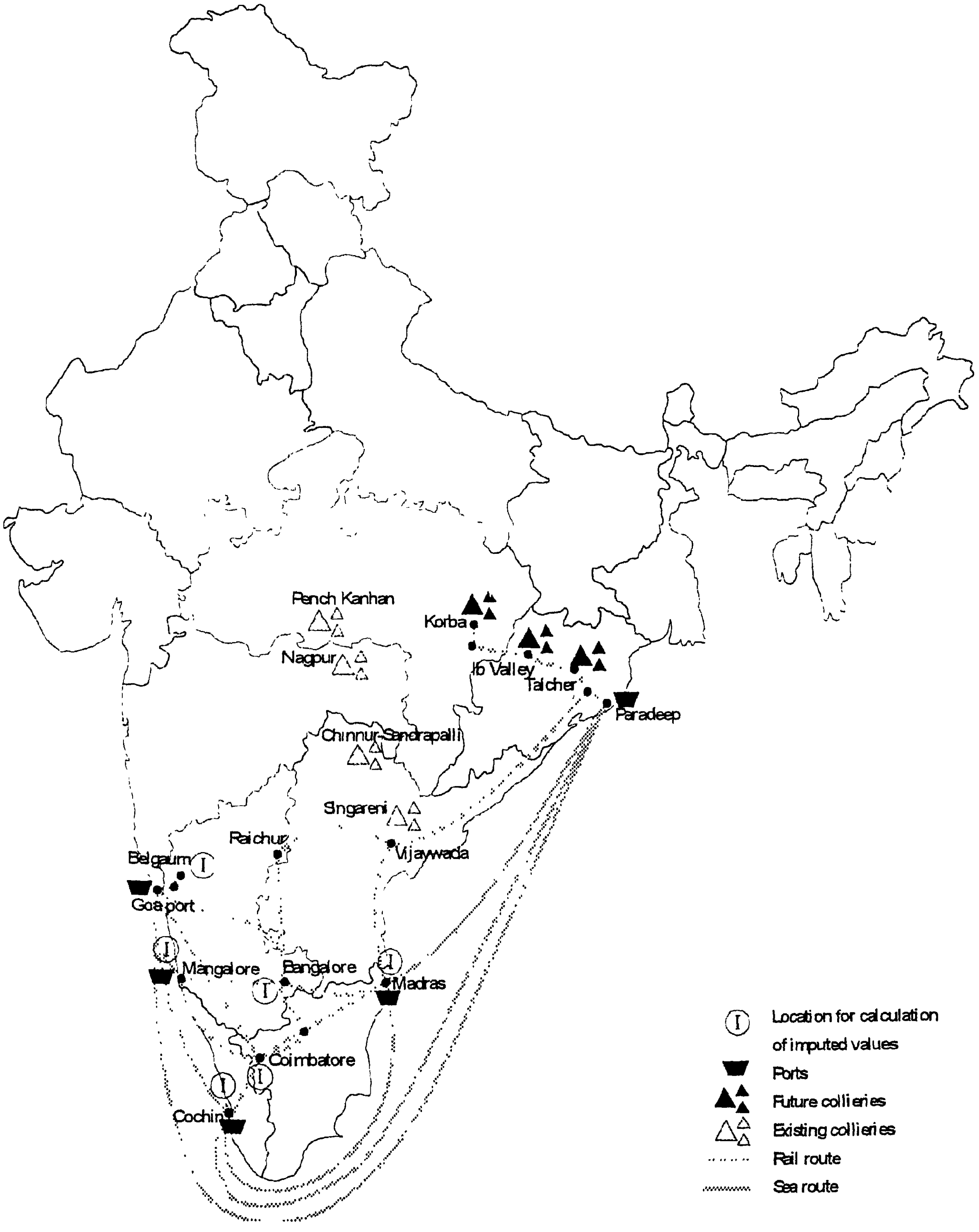
Table 4.25 lists the various technical and financial parameters considered for arriving at the imputed value.

Table 4.25: Technical and financial parameters for coal based plants

S. No.	Technical Parameters	Units	Values
1.	Plant load factor	%	68.50
2.	Auxiliary consumption	%	9.50
3.	Life of plant	Years	25.00
4.	Calorific value (Indigenous)	Kcal/Kg	4200.00
5.	Calorific value (Imported)	Kcal/Kg	7000.00
6.	Heat rate	Kcal/kWh	2500.00
7.	Fixed operating cost	Rs./kWh	0.18

			Values	
S. No.	Financial Parameters	Units	Imported	Indigenous
1.	Discount rate	%	12	12
2.	Capital cost per MW	Rs. million	40	34.7
3.	Investment period	Years	4	4

Figure 4.1: Map showing location of sites for calculation of imputed values



4.6.4. Fuel cost for coal

4.6.4.1. Indigenous coal

The collieries are selected on the basis of their capability to meet coal demand at the sites, infrastructural facilities for shipment & other logistic aspects. The three collieries are Talcher, Ib valley and Korba (as there is no movement possible from the other collieries). F grade Coal is considered whose price at the pithead as Rs 330.20/t. The landed cost at the six locations in the Southern region is arrived at by adding freight to the pithead cost (inclusive of royalty, sales tax etc.).

4.6.4.2. Imported coal

Superior grade steam coal from Australia/S. Africa is considered. The c.i.f. price is US $ 40/t (Rs 1400/t). To arrive at the delivered price at the Indian ports the cost of port handling is added to the c.i.f. price. Finally, the landed price is obtained by adding rail/sea tariffs to the c.i.f. price. Wagon loading and unloading is ignored because of its small charge value. (The customs duty on coal is 20%.)

4.6.5. Naphtha based combined cycle plants

Table 4.26 lists various technical and financial parameters considered for arriving at the imputed value.

Table 4.26: Technical and financial parameters for naphtha based plants

S. No.	Technical Parameters	Units	Values
1.	Plant load factor	%	68.50
2.	Auxiliary consumption	%	3.00
3.	Life of plant	Years	20.00
4.	Calorific value	Kcal/Kg	10560.00
5.	Heat rate	Kcal/kWh	2000.00
6.	Fixed operating cost	Rs./kWh	0.15

S. No.	Financial Parameters	Units	Values
1.	Discount rate	%	12
2.	Capital cost per MW	Rs. million	24.5
3.	Investment period	Years	3

4.6.6. Fuel cost for naphtha

4.6.6.1. Indigenous Naphtha

The ports selected are on the basis of their capacity to meet the demand of naphtha at the sites, infrastructural facilities for shipment & other logistic aspects. The indigenous naphtha will be transported to the sites by rail. The ports are- Cochin, Goa, Madras and Mangalore. The ex-storage price of indigenous naphtha is Rs.

6683/t. Sales tax, excise duty and transportation cost are added to arrive at the landed cost at the site.

4.6.6.2. *Imported Naphtha*

The c.i.f. price of imported Naphtha is Rs. 6784/t ($ 194/t) to which is added rail freight, sales tax, countervailing duty, etc. (The customs duty on naphtha is nil and hence not included.)

The rate of exchange is 1 US $ = Rs. 35.00.

Based on the above assumptions, the replacement values of natural gas for power generation, as a substitute for coal or naphtha, at specific regional centres is finally estimated in the table attached.

The generation costs and imputed values calculated are given in Tables 4.27 and 4 28 respectively while the detailed calculations are given in Appendix 4.4.

The generation cost varies from a low of 4.90 ¢/kWh in the case of a power station using indigenous coal from Talcher and located at Madras, to a high of 6.40 ¢/kWh for a station based on imported coal and located at Coimbatore.

Table 4.27: Cost of power generation with different fuels

(US cents/kWh)

Origin of supply	Imported Coal	Indigenous Coal	Imported Naphtha	Indigenous Naphtha
COCHIN				
Cochin	6.2		5.4	5.6
Talcher		5.1		
Ib valley		5.2		
Korba		5.4		
COIMBATORE				
Cochin			5.6	5.8
Madras	6.4		5.8	6.1
Mangalore				5.9
Talcher		5.3		
Ib valley		5.4		
Korba		5.6		
BANGALORE				
Madras	6.4		5.7	5.9
Cochin			5.9	6.1
Mangalore			5.8	6.1
Goa			6.1	
Talcher		5.3		
Ib valley		5.3		
Korba		5.4		
BELGAUM				
Goa	6.3		5.6	5.8
Talcher		5.7		
Ib valley		5.7		
Korba		5.7		
MADRAS				
Madras	6.2		5.4	5.7
Talcher		4.9		
Ib Valley		5.1		
Korba		5.3		
MANGALORE				
Mangalore	6.2		5.4	5.7
Talcher		5.4		
Ib Valley		5.6		
Korba		5.7		

The imputed values vary from $ 4.56/MMBtu in the case of indigenous coal for Madras from Talcher, to $ 6.95 for a plant based on imported coal in Coimbatore. The majority of the values are above $ 5.00/MMBtu.

Table 4.28: Imputed values of natural gas

(US $/MMBtu)

Origin of supply	Imported Coal	Indigenous Coal	Imported Naphtha	Indigenous Naphtha
COCHIN				
Cochin	6.54		5.33	5.57
Talcher		4.78		
Ib valley		5.04		
Korba		5.30		
COIMBATORE				
Cochin			5.91	6.37
Madras	6.95		5.64	5.96
Mangalore				6.18
Talcher		5.11		
Ib valley		5.37		
Korba		5.64		
BANGALORE				
Madras	6.82		5.75	6.13
Cochin			6.08	6.46
Mangalore			6.01	6.39
Goa			6.48	
Talcher		5.10		
Ib valley		5.10		
Korba		5.25		
BELGAUM				
Goa	6.80		5.64	6.02
Talcher		5.73		
Ib valley		5.73		
Korba		5.84		
MADRAS				
Madras	6.54		5.33	5.80
Talcher		4.56		
Ib Valley		4.82		
Korba		5.08		
MANGALORE				
Mangalore	6.54		5.33	5.71
Talcher		5.34		
Ib Valley		5.59		
Korba		5.86		

4.7. SENSITIVITY ANALYSIS

Sensitivity analysis was carried out for Mangalore site on the imputed values by varying capital cost, heat rate, fuel cost, plant life and plant load factors. Mangalore was considered to be the most likely and representative location of the six considered. The analysis was done with reference to the base case results, which are tabulated in Table 4.33.

The sensitivity analysis shows that the imputed value varies between 7.49 $/MMBtu to 4.51 $/MMBtu for all the factors. The maximum value of the imputed value was in the case of capital cost of coal based power plants, and the minimum value was in the case capital gas based power plants.

The results of the sensitivity analysis are tabulated in Tables 4.29 to 4.38.

Table 4.29: Sensitivity factor - capital cost of natural gas combined cycle power plant

($/MMBtu)

Fuel Sources	$600/kW	$700/kW	$800/kW
Imported Coal	7 02	6 54	6 06
Indigenous Coal			
a) Talcher	5 82	5.34	4.86
b) Ib Valley	6 07	5 59	5.12
c) Korba	6 34	5 86	5 38

Table 4.30: Sensitivity factor- capital cost for coal based plants

($/MMBtu)

Fuel Source	$950/kW	$1000/kW	$1050/kW	$ 1150/kW	$1200/kW	$1300/kW
Imported Coal	5 52	5 79	6 05	6 58	6 84	7.37
Indigenous Coal						
a) Talcher	5 12	5 38	5 65	6 17	6.44	6.97
b) Ib Valley	5 38	5 64	5 90	6.43	6 69	7.22
c) Korba	5 64	5 90	6 17	6 69	6 96	7 49

Table 4.31: Sensitivity factor - efficiency of coal based plants

($/MMBtu)

Fuel Source	40%	39%	34%
Imported Coal	6.00	6 08	6.54
Indigenous Coal			
a) Talcher	4.86	4.93	5.34
b) Ib Valley	5.08	5.16	5.59
c) Korba	5.30	5.39	5.86

Table 4.32: Sensitivity factor - efficiency of natural gas combined cycle plants

($/MMBtu)

Fuel Source	58%	53%	48%
Imported Coal	7.17	6.54	5.93
Indigenous Coal			
a) Talcher	5.85	5.34	4.84
b) Ib Valley	6 13	5 59	5.08
c) Korba	6 42	5 86	5.32

Table 4.33: Sensitivity factor - fuel cost (indigenous naphtha) for combined cycle power plant

($/MMBtu)

Fuel Source	$170/T	$190/T	$210/T	$230/T
Indigenous naphtha	5 08	5 68	6.22	6.88

Table 4.34: Sensitivity factor - fuel cost (imported naphtha) for combined cycle power plant

($/MMBtu)

Fuel Source	$19/barrel	$21/barrel	$24/barrel	$28/barrel
Imported naphtha	4 82	5 33	6.09	7.11

Table 4.35: Sensitivity factor - plant load factor for all power plants

($/MMBtu)

Fuels	55%	68.5%	75%
Indigenous Naphtha	5 71	5 71	5 71
Imported Naphtha	5 33	5 33	5 33
Indigenous Coal			
a) Talcher	5 80	5 34	5 18
b) Ib Valley	6 06	5 59	5 43
c) Korba	6 32	5 86	5 70
Imported Coal	7 20	6 54	6 31

Table 4.36: Sensitivity factor- plant load factor for gas based plant

($/MMBtu)

Fuel Source	55%	68.5%	75%
Indigenous Naphtha	4.89	5.71	6.00
Imported Naphtha	4.51	5.33	5.62
Indigenous Coal			
a) Talcher	4.52	5.34	5.63
b) Ib Valley	4.77	5.59	5.88
c) Korba	5.04	5.86	6.15
Imported Coal	5.72	6.54	6.83

Table 4.37: Sensitivity factor - fuel cost (imported coal)

($/MMBtu)

Fuel Source	$30/T	$40/T	$50/T	$60/T
Imported Coal	5.15	5.84	6.54	7.24

Table 4.38: Sensitivity factor - fuel cost at pithead (indigenous coal)

($/MMBtu)

Fuel Source	Rs.300/T	Rs.330/T	Rs.380/T	Rs.400/T
Indigenous Coal				
a) Talcher	5.26	5.34	5.46	5.51
b) Ib Valley	5.52	5.59	5.72	5.77
c) Korba	5.78	5.86	5.98	6.03

CHAPTER 5
INDUSTRY, CHEMICAL FEEDSTOCK AND OTHER USERS

There exists significant potential demand for natural gas in the cement, fertiliser and iron & steel industries, mainly for capacities which are expected to come up in the next few years. The existing sales potential in billion cubic metres per year in industries other than power for Karnataka, Kerala and Tamil Nadu has been estimated as 0.884, 0.369 and 1.208 respectively. The total future potential has been estimated to be 5.245, 0.569 and 1.370 billion cubic meters per year in Karnataka, Kerala and Tamil Nadu respectively.

5.1 INTRODUCTION

This chapter presents a comprehensive analysis of the industrial, transport and domestic sectors in the three states, aimed at identifying potential markets for natural gas.

The analyses and conclusions are based on wide ranging discussions with potential users, and also on desk research and literature survey; study of various reports and documents; discussions with consultants & research institutions; and considerable information received directly from the corporate sector.

5.2 SUMMARY

The study shows that there is very significant potential demand for natural gas in certain industrial segments and in certain locations. An attempt has been made to identify these and the size of potential markets.

The cement industry, and iron and steel related industry offer sizeable potential market for natural gas. The biggest potential appears to exist in three or four districts in Karnataka. While sizeable potential could exist in fertiliser industry, this would require significant investment to be able to change over to natural gas, since the plants have been originally designed for using furnace oil. The plants currently using naphtha could switch to natural gas with much lower investment.

The southern states are far away from supply source of coal which is the cheapest form of fuel, and this has stunted the growth of industries requiring large quantities of fuel, even though other inputs are available in the area. The problem in using coal is not only the cost factor which include a large element of transportation cost, but the irregular and erratic supply line which makes the plant using coal maintain large inventories.

Availability of natural gas would provide great relief to industries requiring large quantities of fuel. The potential demand for natural gas as indicated by this survey is quite large, but the latent demand in the long term could be several times more, since the prospect of easy, ready and stable supply prospect of natural gas could trigger a very rapid growth of large industries, which hitherto was not economical.

However, one of the key factors is the pricing of natural gas. It is the general expectation among the potential users of natural gas, that substituting the present fuel or feedstock by natural gas when it becomes available will not result in net increase in energy costs. There are several benefits, advantages and economies that result from using natural gas, and it should be possible to impute values to these while determining the comparative price for natural gas supplies.

While there is generally a welcome response to the prospect of availability of natural gas amongst the potential users, there appears to be a considerable information/knowledge gap, as most of them have no prior experience in using natural gas. These relate to the mode of supply; need and cost of storage at plants; safety aspects; process changes required to be made; reliability of supply; energy cost implications and so on. It is very desirable that some effective mode of communication is established (either through press, circulation of information booklets, seminars, etc.) to educate and familiarise the potential users on the various technical and supply issues, so as to bridge the information gap.

5.3 CEMENT INDUSTRY

5.3.1. Industry profile

The cement industry offers a very large potential for natural gas in the southern states as a coal substitute. Some of the salient features of the industry as a whole are briefly discussed.

India is the fourth largest cement producing country in the world, after China, Japan and US. But the per capita consumption of cement in India is very low, even compared to some other developing countries. There is a very large potential for growth of this industry, consequent to improving living standards and increase in GDP.

The cement industry in India is the third largest consumer of coal after power plants and steel industry - accounting for about 5-7 percent of coal produced in the country. It is estimated that cement industry would require about 16 million tons (MMT) of coal per year by 1997 and about 20-25 MMT/year by turn of the century.

The total installed capacity of cement industry in the country was about 76 MMT as on 30.3.95 and cement production during the year 1994-95 was 58.35 MMT. There were 106 cement plants controlled by some 55 companies. Five large industrial groups - ACC; various branches of Birla family; L & T; Cement Corporation (GOI); and JK group command more than 50 percent of capacity and 50 of the 106 cement plants in the country.

The demand for cement in 1996-97 is expected to be around 77 MMT including 5 MMT planned exports. The rate of growth of demand is expected to be of the order of 8.5 percent and by the turn of century the country would have more than 100 MMT installed cement producing capacity, considering the extent of licences issued for new plants and substantial expansion.

The total cement grade limestone deposits in India are estimated to be 90 billion metric tons - about 80 percent of which are located in 6 states, mostly in large clusters besides some isolated smaller scattered deposits. About 56 percent of cement producing capacity at present is concentrated around these cluster areas. Four of the seven clusters are located in Southern Region.

5.3.2. Size of industry in South

Andhra Pradesh and Karnataka states have large cement grade lime stone clusters. Tamil Nadu does not have any large cluster formation but has significant scattered deposits and has some large cement plants. Kerala has one medium size cement plant. Andhra Pradesh is excluded from the purview of this study.

Table 5.1: Location of cement plants and their capacity

Name of the Unit	Location	Capacity (Million TPA)
TAMIL NADU		
ACC Limited	Maddukkai	0.52
India Cements Limited	Sankaridurg	0.60
Chettinad Cements	Karur	0.60
India Cements Limited	Talaiyuthu	1.10
Tamil Nadu Cements	Alangulam	0.40
Madras Cements Limited	Tulukapatti	0.75
Dalmia Cement Limited	Dalmiapuram	0.53
Tamil Nadu Cements	Ariyalur	0.50
KARNATAKA		
HMP Cements Limited	Shahabad	0.48
ACC Limited	Wadi	2.00
Vasavadatta Cements	Sedam	0.50
Rajashree Cements	Malkhed	1.80
CCI Limited	Kurkunta	0.20
Kanoria Industries	Bagalkot	0.33
Mysore Cements	Ammasandra	0.57
Visvesvaraya Iron & Steel	Bhadravati	0.10
KERALA		
Malabar Cements	Palghat	0.42

Table 5.2: Cement: new plants & expansions

NAME OF THE UNIT	LOCATION	Capacity million TPA
KARNATAKA		
Wadi Cement	Gulbarga Dist	4.00
Rajashree Cement Ltd.	Aditya Nagar, Gulbarga Dist.	1.20
Kitply Inds. Ltd	Chittapur, Gulbarga Dist.	2.00
Arvind Mills Ltd.	Chittapur, Gulbarga Dist.	1.00
Mysore Cement Ltd.	Sedam, Gulbarga Dist.	1.50
Raymonds Cement Works	Chittapur, Gulbarga Dist.	2.00
Kanoria Inds. Ltd.	Bagalkot, Bijapur Dist.	0.33
Paper Packaging Pvt. Ltd.	Bagalkot, Bijapur Dist.	2.00
Kesoram Industries Ltd.	Sedam, Gulbarga Dist.	1.18
NEPC-Micon Ltd.		1.00
Total		**16.21**
TAMIL NADU		
Madras Cements Ltd.	Ariyalur, Tiruchirapalli Dist.	0.90
Tamil Nadu Cements Corpn. Ltd.	Alangulam, Kamarajar Dist.	0.50
Dharani Cements Ltd.	Ariyalur, Tiruchirapalli Dist.	0.60
Dalmia Cement Ltd.	Dalmiapuram, Tiruchirapalli Dist.	1.10
India Cement Ltd.	Trichy, Tiruchirapalli Dist.	0.70
Total		**3.80**

Some of the large scale expansion of the existing plants and new plants are expected to be commissioned within the next 2-3 years, particularly in Karnataka.

It is expected by the turn of the century, the installed capacity of cement plants in Karnataka would exceed 10 million tons but the expansion of the cement industry in Tamil Nadu is not likely to be as spectacular.

The entire cement industry in Karnataka (except for two small plants), and location of several new plants are all close to Wadi cluster confined to just one district - Gulbarga. That is, more than 10 million tonnes of cement capacity by the turn of the century will be located in Gulbarga district (close to Wadi cluster); and it is expected the industry would continue the trend of rapid growth.

5.3.3. Comparative advantages of Natural gas

5.3.3.1. Present fuel cost

Cement industry is very energy intensive and between 30-35 percent of manufacturing cost is on account of energy. A major part of energy cost is contributed by coal and the rest by electricity.

It is estimated that the quantity of coal required is about 20 percent of quantity of cement production. That is, an output of 1 million tons of cement requires about 0.2 million tons of coal. Assuming that the cement production will reach 10 MMT by turn of the century at Wadi cluster, the requirement of coal in the district for cement plants alone would be of the order of 2 MMT.

The type of coal required for manufacturing cement is of lower grade - D - grade slack coal with useful heat value of 4200 - 4900 Kcal/kg - with ash content of 28-36 percent.

In manufacture of cement, coal is burnt (pyroprocessing) in the kilns along with limestone to produce clinker. Burning of coal provides the required heat and temperature for formation of clinker, and also the residual ash (silica) in the coal is an input to form clinker. While cement manufacture can use low grade coal, the wide variation in the quality of coal makes the task of maintaining uniform balance of limestone & silica (ash content) in the clinker very difficult, affecting the quality of end product.

The cement plants in South India are very far from coal producing locations; and landed cost of coal at site including transportation works out to 3 to 4 times the purchase cost of coal. The cost of coal at a cement plant in either Tamil Nadu and Karnataka works out to between Rs. 1200 - Rs. 1600 per ton, depending on the location.

While the cost of coal at the pithead is somewhat stable, the transportation cost increase is a normal annual feature, since the (nationalised) railway tariff revision is almost a regular exercise every year. This pushes up the cost of delivered coal at site almost every year.

Natural gas technically can substitute coal with minor modifications to the burner, with great advantage. In view of the stiff competition amongst producers where price is one of the major factors, the cement industry would be averse to incurring increased energy costs, as this may adversely affect their profitability and/or competitiveness in the market.

However, there are certain indirect positive quality, cost and efficiency implications in using natural gas, which become very relevant in the analysis for determining the comparable and competitive cost for natural gas.

- Use of natural gas in place of coal would obviate the need for coal handling, crushing and grinding machinery – in the range of Rs. 100 million for a one million ton plant. While this investment could be saved in new plants using natural gas, in the existing plants which may switch over from coal to natural gas there may not be much savings since the investment has already been made. But, use of natural gas would save about 25 kWh of power/ton consumed on handling, crushing and grinding of coal.

- The availability of coal and railway wagons for transporting is so erratic and uncertain, the cement plants in the south normally stock coal for up to 6-8 months' requirements. The financial burden on account of this inventory could be significant – up to 22 - 25 percent of investment on stocks. Using natural gas would eliminate this cost.

- The quality of coal supplied is very uneven in terms of ash content and heat value. As a result, producing uniform quality clinkers/cement becomes difficult because of changing mix of limestone and silica (ash). Besides, efficient and uniform burning in the kilns which is critical for producing quality clinkers/cement is difficult because of changing heat value of coal. Such problems will not exist in case of natural gas and the quality of clinker produced would be uniform since it is easy to maintain uniform mix of limestone and silica.

- Use of natural gas gives longer life for refractory lining and reduces down time of the kilns.

- The output /production/productivity of kilns is expected to improve by at least 10 percent, in kilns and some estimates place it at 20-25, percent if coal is substituted by natural gas. This would be a tremendous advantage, since more production is achieved for a smaller investment.

- As far as the cost of adaptation from coal to natural gas is concerned, some changes would have to be made in the burners of the kilns, but they would not involve any major investments.

The surveys and discussions with industry show that by and large, availability of natural gas would be a most welcome development and most would change over to natural gas when available, only if the price is competitive. Any increase in net energy cost would discourage potential users. However, values have to be imputed

to the various savings that would result by using natural gas, while determining the price for natural gas.

5.3.4. Size of market & pricing

It is anticipated that in Gulbarga district alone, the production of cement may reach about 10 MMT or more by turn of century and would continue to expand. Most of the plants are expected to be supported by captive coal fired thermal power plants. The likely demand for coal is expected to be about 2 MMT by the turn of the century. In terms of natural gas equivalent, 2 million ton coal would be 0.82 billion m^3 .

The Tiruchirapalli district will have cement plant capacity of 5 MMT by turn of century and this will mean demand for coal of about 1 MMT. In terms of natural gas equivalent for one million ton coal would be 0.41 billion m^3.

The price level indicated by a major cement producer as acceptable was in the range of Rs. 0.35 to Rs. 0.40/thousand Kcal equivalent to gas cost Rs. 3066 - 3504/thousand m^3 of natural gas ($ 2.50 - $ 2.88/MMBtu).

5.4. IRON & STEEL

5.4.1. Integrated steel plants

There is only one integrated steel plant in the three states, the Visveswaraya Iron & Steel Ltd., Bhadravati with a blast furnace capacity of 600 tons of hot metal per day. The plant is now being managed by Steel Authority of India Ltd.

A number of new plants in Karnataka are planned and have been approved for power and fuel linkages (coal). A consolidated list of these plants is given in Table 5.3.

Table 5.3: Iron & steel plants

Name of unit	Location	Type of Product	Capacity million TPA
EXISTING			
VISL	Bhadravati	Integrated Steel Plant	0.18
APPROVED PROJECTS			
Kirloskar oil Engines	Koppal, Raichur Dist	Pig Iron & Foundry	0.12
JESCO	Mangalore, D. K. Dist	Integrated steel plant	0.50
Jindal Vijayanagar steel Ltd	Hospet, Bellary Dist	Integrated steel plant	1.25
Kalyani steel Ltd	Koppal, Raichur Dist	Pig Iron & Engg. steel	0.23
Elkaysteels	Hospet, Bellary Dist	Pig Iron	0.25
ARM Ltd.	Raichur, Raichur Dist	Pig Iron	0.40
Dalton Ltd.	Hospet, Bellary Dist	Steel	0.21
Bellary steels & Alloys Ltd	Bellary, Bellary Dist	Long bars & Flat products	0.38
Usha Iron & ferro Metals	Bramhavar, D.K Dist	Integrated steel plant	2.00
Canara steels Ltd	Balkampady, D.K. Dist	Steel plant	0.30
Mittal steel Ltd	Bellary	steel plant	0.36
Kap steel Ltd	White field, Bangalore Dist	Steel plant	0.26
TOTAL			**6.43**

The coke consumption of the VISL blast furnace is 670 kg/ton of hot metal and amounts to nearly 0.12 million TPA of coke. It is possible to reduce consumption of coke and increase furnace output by enriching the gas fed through the tuyeres. It has been amply demonstrated in Britain, Japan, America, Italy & India that injection of natural gas and oxygen can contribute significantly to improvement of blast furnace. VISL has also been using blast Furnace (BF) gas for reheating and heat treatment furnaces, but has been facing difficulty in flame sustenance due to very low GCV of the gas. The plant has been exploring means of enriching this gas. There exists a potential for natural gas to be used for enrichment of BF gas for use in the furnaces.

The total potential of natural gas in the iron & steel industry will be more apparent after the future projects start production. A marketing exercise would be necessary to bring to fore this 'latent' potential.

KUDREMUKH IRON ORE PROJECT - PELLETISATION PLANT

This plant produces nearly 5000 T per month of iron ore pellets. The technology involves sizing and homogenisation of iron ore, addition of binder to sized iron ore and baking of bound ore to form pellets. The pellets form an input to blast furnaces. Heat input is required for baking.

Since the plant is located near Mangalore, it offers a good though limited potential for switching over to natural gas in the heating processes.

5.4.2. Sponge iron plants

Natural gas is used in 2 plants out of the total 11 sponge iron plants in the country. There is only one plant producing sponge iron (DRI) in the three states. The plant is located at Bellary in Karnataka.

The plant has 2 sponge iron kilns with a combined capacity of 6000 TPA. The kilns are coal fired. Coal is transported over long distances from Singareni and Nagpur by rail wagons.

The plant is integrating a Blast Furnace and natural gas is an alternative fuel both for sponge iron and Blast Furnace route of steel making. The prices of coal and coke are very high and natural gas is a very competitive option.

Natural gas gives a better degree of metallisation in sponge iron compared to coal. Thus, the availability of natural gas from a suitably located terminal is expected to provide impetus to sponge iron industry in this region and there is a strong likelihood of more plants coming up. The potential of natural gas can therefore not be restricted to the existing plant only.

5.5 FERTILISER INDUSTRY

5.5.1. Industry profile

The nitrogenous fertiliser industry is highly energy intensive and one of the largest consumers of petroleum based fuels.

The installed capacity of nitrogenous and phosphatic fertiliser industry in India is 8.844 million tons and 2.829 million tons of nutrients respectively.

Many different feedstocks are used e.g. coal, coke, heavy oil, naphtha, natural gas, industrial gases etc., for the production of ammonia depending on the actual availability of feedstock. Today more than 75 percent of the total world ammonia capacity is based on natural gas.

The major part of the feedstock is consumed by the process as feed in ammonia production. Nearly 74% of the feedstock is used as feed consumption and 26% as fuel consumption.

The minimum theoretical energy consumption for the production of ammonia, regardless of production process, based on LHV (Lower Heating Value) of feedstock

is 17 GJ/t of ammonia. The minimum practical requirement of natural gas (CH_4 content 81.3%) for ammonia is nearly 603 m^3/t of ammonia.

5.5.2. Industry description

The fertiliser industry in Southern India offers potential for natural gas as the plants in Tamil Nadu, Karnataka & Kerala are using naphtha as feedstock because there is no present source of gas. It is generally known that the most energy efficient production of ammonia is achieved by using natural gas.

Table 5.4 lists the major manufacturers of nitrogenous fertilisers in the three states.

Table 5.4: Fertiliser industries

Name of the Industry	Location/State	Capacity (MMTPA)
Mangalore Chemicals & Fertilisers Ltd	Mangalore, Karnataka	339900 (Urea) 1500000 (DAP)
Fertilisers & Chemicals Travancore Ltd	Cochin, Kerala	**Ammonia** Unit - I - 38400 Unit - II - 192000 New RAP - 288000
SPIC	Tuticorin, Tamil Nadu	Ammonia - 352000 Urea - 512000
Madras Fertilisers Ltd	Manali, Tamil Nadu	273800 (Ammonia)
Tuticorin Alkali Chemicals & Fertilisers Ltd	Tuticorin, Tamil Nadu	73000 (Soda Ash) 67200 (Ammonium Chlorite)

The state wise summary for ammonia plant capacities is as below :-

Tamil Nadu - 6,25,800 TPA, Kerala - 2,83,800 TPA & Karnataka - 2,17,800 TPA

The Production capacities and technologies being used by the plants are as under:

MANGALORE CHEMICALS & FERTILISERS LTD.

Plant : Panambur, Mangalore, Karnataka,

Capacity: Ammonia Plant: 2,17,800 MMT per annum; Urea Plant: 3,40,000 MMT per annum: Diammonium Phosphate Plant: 1,38,000 MMT per annum; Ammonium Bi-Carbonate Plant (ABC) : 3600 MMT per annum.

Process Employed: Single stream plant with Naphtha as feedstock for Ammonia Plant and conventional process for DAP plant with imported phosphoric acid and Ammonia as major raw-materials.

The company has also set up a captive power plant consisting of 8 nos. D.G. sets of the capacity of 6.5 MW each at a cost of Rs. 315 million.

FERTILISERS AND CHEMICALS TRAVANCORE LIMITED

Production Divisions : 1. Udyogamandal Division, Udyogamandal, Cochin; 2. Cochin Division : Ambalamedu, Cochin, 3. FACT Petrochemical Division, Udyogamandal, Cochin.

Capacity : Ammonia : 2,83,800 TPA; Ammonium Sulphate : 2,25,000 TPA; Caprolactam: 50,000 TPA; Complex Fertilisers (Factamfos/DAP) - 6,33,500 TPA; Sulphuric Acid - 7,09,500 TPA; Phosphoric Acid - 1,48,000 TPA; Urea - 3,30,000 TPA; Nitric Acid - 3,800 TPA; Soda Ash - 4,750 TPA.

Process Employed : Udyogamandal : Ammonia - Texaco-Hitachi-ICI; Sulphuric Acid - Simon Carves/FEDO; Phosphoric Acid - Dorr Oliver; Ammonium Phosphate - Dorr Oliver. Cochin: Ammonia - Power Gas, Montecatini; Sulphuric Acid - Bayer/Davy Power Gas; Urea - Montecatini; Complex Fertilisers - Wellman Lord. Petrochemical: Caprolactam (By Products: Nitric Acid & Soda Ash) - Stamicarbon, b.v.

SOUTHERN PETROCHEMICAL INDUSTRIES CORPORATION LTD. (SPIC)

Plant: 'SPIC Nagar', Tuticorin, Tamil Nadu.

Capacity: Ammonia - 3,52,000 TPA; Urea - 5,12,000 TPA; Sulphuric Acid - 1,50,000 TPA; Phosphoric Acid - 52,800 TPA; DAP - I Plant 1,60,000 TPA; DAP - II Plant - 1,50,000 TPA; DAP - I Retrofit - 1,05,000 TPA.

Process Employed: Ammonia - ICI's Naphtha Steam Reformation Process; Urea - Mitsui - Toatsu's improve 'C' Process (Total Recycle); Sulphuric Acid - Nissan Process; Phosphoric Acid - Nissan Process; DAP - TVA Process; DAP-I Retrofitting - Double Gun Process developed by GESA, France.

MADRAS FERTILISERS LIMITED

Plant: Manali, Madras.

Capacity: Ammonia: 750 TPD; Urea: 885 TPD; NPK: 1800 TPD.

5.5.3. Potential for natural gas

The potential for natural gas in these units has been assessed based on discussions with the concerned plant managers and executives.

The officers at the Fertiliser Association of India, which is the representative body of all Indian fertiliser manufacturers, were of the opinion that any fertiliser plant would be glad to switch to natural gas from naphtha due to elimination of fuel-storage requirements and lower maintenance requirements. According to them, there exists a marginal surplus in fertiliser capacity in the south, while there is a large deficit in the north. Due to this reason, most new capacity additions are being planned in the north. Also, the western region has a large surplus, and could supply the southern parts of the country if the need arises.

FERTILISERS AND CHEMICALS TRAVANCORE LIMITED, COCHIN

FACT has 2 ammonia plants of capacity 120 TPD & 600 TPD, based on naphtha as feedstock. One more ammonia plant of 900 TPD is to commissioned within 1998. The new plant can use either naphtha as natural gas and its technology is provided by Halder Topsoe. The total requirement of naphtha for existing plants is nearly 570 TPD. This is equivalent to about 673,000 m^3 per day of Natural Gas. The potential requirement for the new plant would be about 855,000 m^3 per day of natural gas.

The company is definitely interested in sourcing natural gas to meet its feedstock requirement. The advantages of using natural gas like better efficiency and feedstock cost savings are already known to the plant and the new plant has been designed to use gas, whenever gas supply source is

available. The existing plants would need retrofitting to enable them to use gas.

MANGALORE CHEMICALS & FERTILISERS LTD. MANGALORE

The capacity of ammonia plant is 2,17,800 TPA. The plant uses naphtha as feedstock which is available to the plant at the special fertiliser price of Rs. 4050/T. The plant uses FO for generating steam in boilers.

The plant would seriously consider shifting to natural gas as feedstock and fuel. The annual potential for natural gas is estimated at 275 MMSCM for replacing naphtha & FO in the plant. Major modifications in the plant are required to be carried out for use of natural gas, since the existing plant is designed to run on naphtha & fuel oil.

SOUTHERN PETROCHEMICAL INDUSTRIES CORPORATION LTD.

The capacity of ammonia plant is 3,52,000 TPA based on naphtha and FO.

Since the existing plant will need major modifications to switch over to natural gas, it seems less inclined towards gas as feedstock unless firm pricing and assured supplies are established. SPIC is finalising a plan to put up a joint venture for manufacturing ammonia through natural gas route in the Middle East. The potential for natural gas is large but not easily quantifiable considering the group's activities in parallel marketing of LPG and petrochemical interests.

5.5.4. Conclusion

All fertiliser plants are supplied with naphtha at a special fertiliser price which is heavily subsidised compared to market price fixed by government of naphtha. Potential exists in plants which have been designed for naphtha and FO as feedstock, but major modifications are to be made in pre-reformer, gas pre-heater etc., which would entail investment that will have to be justified by cost savings from switching of feedstock to gas. The potential of a switch to natural gas in fertiliser industry would thus depend largely on pricing of natural gas.

As regards new fertiliser plants on natural gas, the current thinking in India is to base these plants in the Gulf countries (with cheap and reliable access to gas), and

ship the fertiliser as dry cargo to India. Therefore, for the present, no new grassroots fertiliser plant on natural gas is considered in the projections.

5.6 PETROCHEMICAL INDUSTRIES

The potential in related major industries was also assessed and a partial list of these industries including, Heavy Chemicals, Insecticides, Petrochemicals, Metal extraction is given in Table 5.5.

Table 5.5: Petrochemical industries

Name of the Industry	Type	Location/State	Capacity (MMTPA)
Kerala Minerals & Metals Ltd	Metal extraction	Quilon, Kerala	22000 TDP
Hindustan Insecticides Ltd	Pesticides & Insecticides	Cochin, Kerala	1200 DDT 3000 DHC 1670 ES 150 Dicofo
The Travancore Cochin Chemicals Ltd	Chemical	Cochin, Kerala	-
FACT Petro Chemicals Ltd	Petro Chemical	Cochin, Kerala	-
SPIC	Petro Chemical	Madras, Tamil Nadu	5.60 million - Urea 0.38 million - Ammonia 0.77 million - LPG
UB Petro Products Ltd	Petro Products	Madras, Tamil Nadu	1200 PO 8250 PG 8000 PE
Tamil Nadu Petro Products Ltd	Petro Products	Madras, Tamil Nadu	85000 Linear Alkalis 10000 ECH
Manali Petro Chemicals Ltd	Petro Chemicals	Madras, Tamil Nadu	12000 PO 6250 PG 6000 Polyoes
Dalmia Magnesite Corporation	Magnesite	Salem, Tamil Nadu	72000 Dead Burn Magnesite

Most of these potential industries are using fuels like LPG, FO, LSHS and petroleum coke in boilers, furnaces, dryers etc.

The foreign collaborators of some of these companies use NG in their plants abroad and the plants in this country have been modified to fire available fuels. Industries like petrochemicals and insecticides use intermediates which are synthesised from minor fractions of natural gas and thus the potential of NG in all the above industries is as an alternative fuel especially for LPG.

The Madras Refinery Limited (MRL) and SPIC are planning a joint venture petrochemical unit (Arochem Industries). The feedstock will be naphtha from the refinery and hence the possibility of using natural gas may be ruled out.

The overall potential of natural gas for this sector is therefore small.

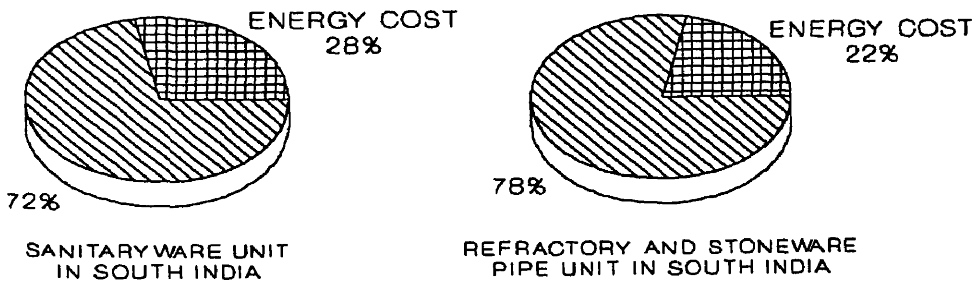
5.7 OTHER INDUSTRIES

5.7.1. Ceramic industries

The ceramic units are spread throughout the country and encompass the small (cottage), medium and large scale sectors.

Fuel accounts for around 15-20% of the total manufacturing cost in a ceramic unit. Variations depend on the region where the unit is located. Ceramic industry is densely located in western part of the country. Typical energy costs for some of the units in South India are given in Figure 5.1.

Figure 5.1: Energy costs for ceramic industries in South India



The potential for natural gas in ceramic industry in southern India appears to be marginal, since the size of the industry is small.

Table 5.6: Prominent ceramic plants

Name of the Industry	Location/State	Capacity (TPA)
Murudeshwar Ceramics Ltd	Hubli, Karnataka	
EID Parry (Ceramics Division)	Chengai Anna Dist. Tamil Nadu	
SPARTEK Ceramics Ltd	AP, Tamil Nadu, Pondicherry	14000 (Sq.m/day (Tiles) 3600 (Sanitary Ware)
The Kerala Ceramics Ltd	Quilon Dist., Kerala	600 (Ceramic Wares) 1200 (China Clay)
BHEL	Bangalore, Karnataka	5900 Insulator 745 Ceralin 1300 Foundry Refractory

Natural gas offers a number of advantages over other fuels in the ceramic industry such as:-

1. Increased furnace efficiency
2. Continuity of production and temperature consistency leading to better product quality
3. No contamination of product from fuel
4. Cost effectiveness

By changing over from coal to oil/natural gas there would be saving of energy due to proper combustion of fuel and uniform circulation of heat throughout the Kiln. It is expected that this saving in energy consumption could be to the extent of 40-50 percent.

When natural gas becomes available, this industry is likely to switch over to it, if the net energy cost is competitive.

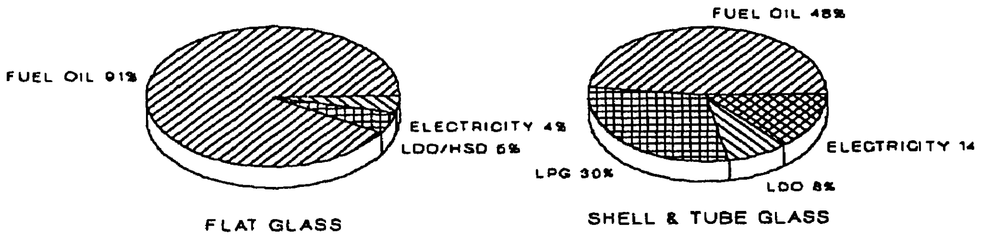
5.7.2. Glass industry

Glass manufacture is an energy intensive industry consuming energy worth Rs. 2 billion for a production of about 1.2 million tons of various glass products.

In a glass unit fuel and power constitutes 16 to 45% of total production cost which is mainly dependent on the type of end product. In shell and tube manufacturing, the percentage being minimum and for sheet glass manufacturing it is maximum.

The share of different forms of energy used in glass manufacture is shown in Figure 5.2.

Figure 5.2: Shares of different forms of energy used in glass industries



The glass industry has four units in the three States as given in Table 5.7.

Table 5.7: Glass industries

Name of the Industry	**Location/State**	**Capacity (TPA)**
The Mysore Lamp Work Limited	Bangalore, Karnataka	-
Victory Glass & Industries Limited	Bangalore, Karnataka	-
Excel Glasses Limited	Alleppey, Kerala	-
Eagle Flask Industries Limited	Madras, Tamil Nadu	2900
Note: '-' indicates that the information was not available.		

The glass industry is using furnace oil for furnaces and LPG for reheating, melting & annealing lehrs[1]. The furnace oil can be fully replaced by natural gas and LPG can be replaced partially. Glass furnaces, once fired, run uninterrupted for long periods of over 3 years. Hence, these furnace demand uninterrupted fuel supplies. Natural gas as a fuel can be considered only if such supply arrangements are promised and demonstrated in other industries. The glass industry expects that use of natural gas could result in 40 - 50 % decrease in fuel costs and this margin would be attractive for fuel switching to gas.

5.7.3. Textiles

There are clusters of textile mills at Coimbatore in Tamil Nadu, Palghat in Kerala and Dharwad & Bijapur in Karnataka. Most of these mills are spinning units and utilise electric power. The composite textile units using coal or petroleum fuels are few and given in Table 5.8.

Table 5.8: Textiles industries using coal or petroleum fuels

Name of the Industry	**Location/State**
Binny Limited	Madras, Tamil Nadu
The Dhanalakshmi Mills Limited	Coimbatore, Tamil Nadu
Lakshmi Mills Company Limited	Coimbatore, Tamil Nadu
Madura Coats Limited	Madurai, Tamil Nadu
Varadhalakshmi Mills Limited	Madurai, Tamil Nadu
Veena Textiles Limited	Komarapalayam, Tamil Nadu

The fuel input is mainly for boilers and thermic fluid heaters in fabric production and dyeing. The only advantage of using natural gas is drastic reduction in fuel costs which have made products of textile industries from Gujarat very competitive. The textile industry would prefer to use natural gas without putting in much capital as the textile industries in these three states are not doing well. The potential for natural gas in textile industry can be considered to be marginal.

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[1] A 'lehr' is a furnace used for the annealing of glass.

5.8 CONCLUSION

The study indicates that there is significant potential market for natural gas in the three Southern states. More than the existing potential, when the prospect of availability of natural gas becomes real, it could trigger a very rapid development of large industries in the area using natural gas such as iron & steel, cement, petrochemicals, fertilisers, textile processing and other industries, which can increase the demand for natural gas several fold than what has been indicated earlier. Table 5.9 shows the potential for natural gas sales as indicated by surveys.

Table 5.9: Natural gas sales potential in industries (excluding power sector)

(BCM/year)

Industry	**Karnataka**		**Kerala**		**Tamil Nadu**	
	Existing	**Future**	**Existing**	**Future**	**Existing**	**Future**
Cement	0.551	2.105	0.040	0.040	0.535	0.697
Fertiliser	0.235	0.235	0.160	0.360	0.565	0.565
Iron & Steel	0.098	2.905	0.000	0.000	0.000	0.000
Petrochemical	0.000	0.000	0.169	0.169	0.108	0.108
TOTAL	**0.884**	**5.245**	**0.369**	**0.569**	**1.208**	**1.370**

However, one of the most important factor for the potential to translate into market is the comparative cost. The cost of natural gas should compare favourably with the cost of coal or any other fuel it substitutes in terms of calorific value rating, and values can be imputed towards the other benefits derived from use of natural gas.

The three southern states are thousands of kilometres away from coal mines, and the cost and uncertainty factors associated with supply and delivery of coal, have retarded rapid growth of industries requiring large quantities of coal, even though other basic raw materials and/or markets exist in the area.

CHAPTER 6
DEMAND CONCLUSIONS AND LNG TERMINAL OPTIONS

6.1. AREAS OF ELECTRICITY DEMAND

There are three sectors with localised electricity demand; industrial, commercial and domestic. Of these, commercial and domestic sectoral demands would be centred in every city in the three states. This is not true for the industrial sector as not every city has an industrial area.

In Karnataka, the industrial centres are located around Bangalore, Mangalore, Gulbarga and Raichur. In the case of Kerala, the major industrial centre is Cochin, while in Tamil Nadu, industrial clusters are located near Madras, Tuticorin and Coimbatore. These cities are shown on the individual state maps on the following pages.

As per the analysis carried out in the chapter on Power Generation (Chapter 4), a shortfall in installed capacity of electricity is only likely for the high growth scenario for Karnataka in the year 2015. This shortfall is of the order of 400 MW, and can be easily met by importing power from Tamil Nadu and/or Kerala as they are expected to have surplus capacity.

6.2. AREAS OF NATURAL GAS DEMAND

The planned capacity additions in the power sector open up a large potential for sale of natural gas. Major gas based power plants are coming up around Kasargod in Kerala and Madras in Tamil Nadu. In Karnataka, many liquid fuel based projects are being set up near Mangalore, and these offer considerable scope for switching to natural gas. The major existing and proposed power projects are shown on the state maps on the following pages.

In addition, the potential for, location-wise, for use of natural gas as a substitute for coal and naphtha in the cement, fertiliser and iron & steel industries have been covered earlier in Chapter 5.

Figure 6.1: Map of South India

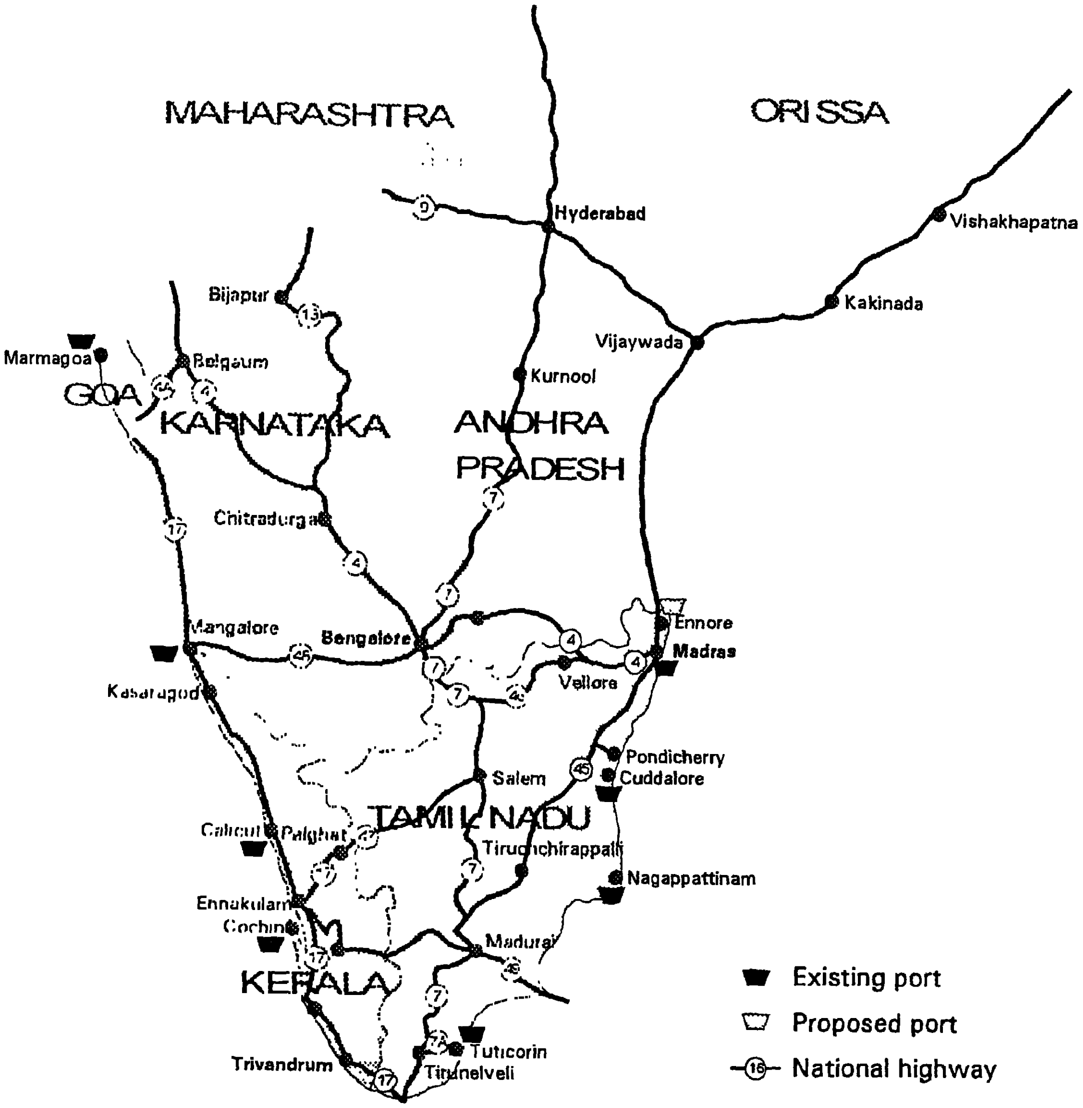


Figure 6.2: Map of Karnataka

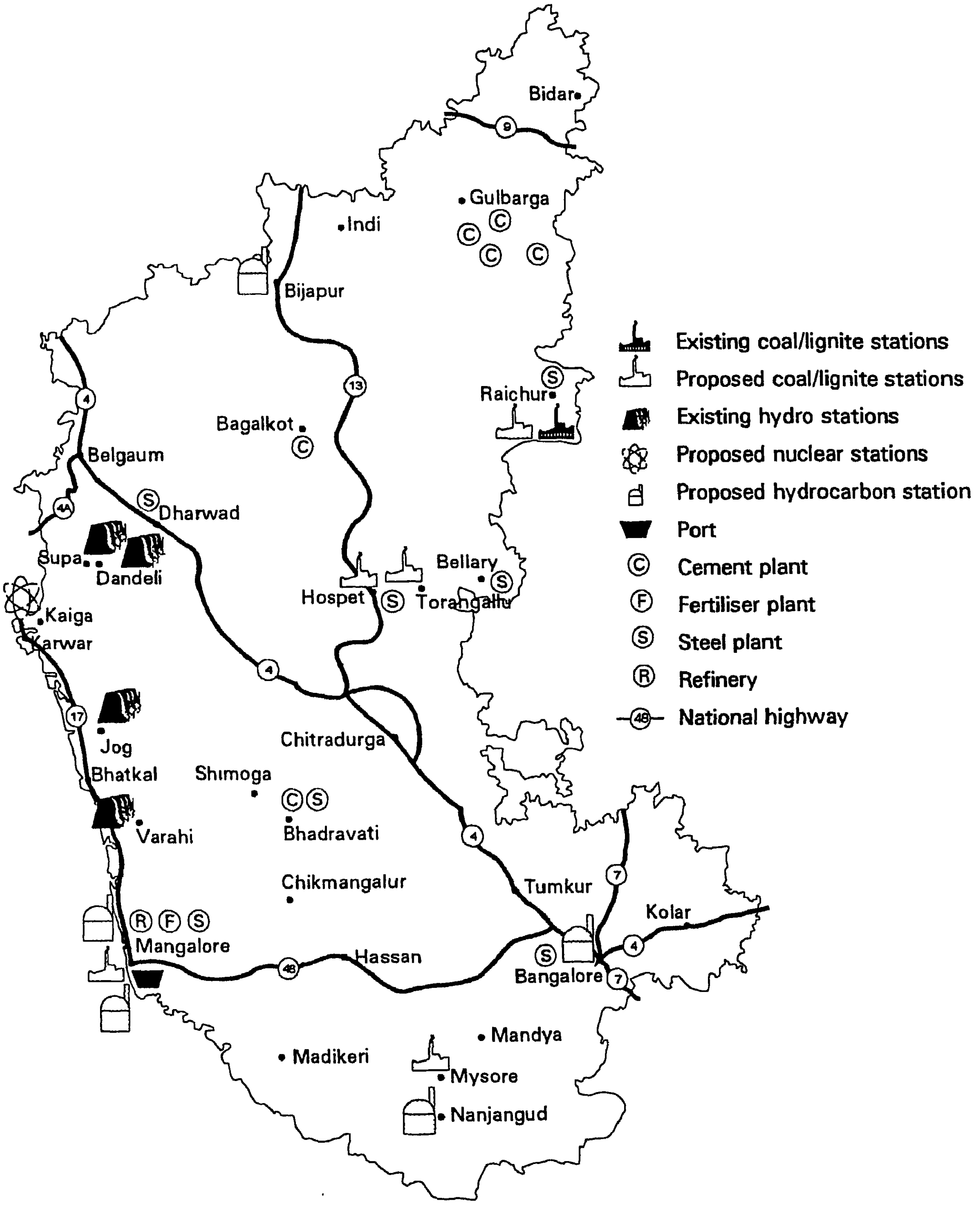
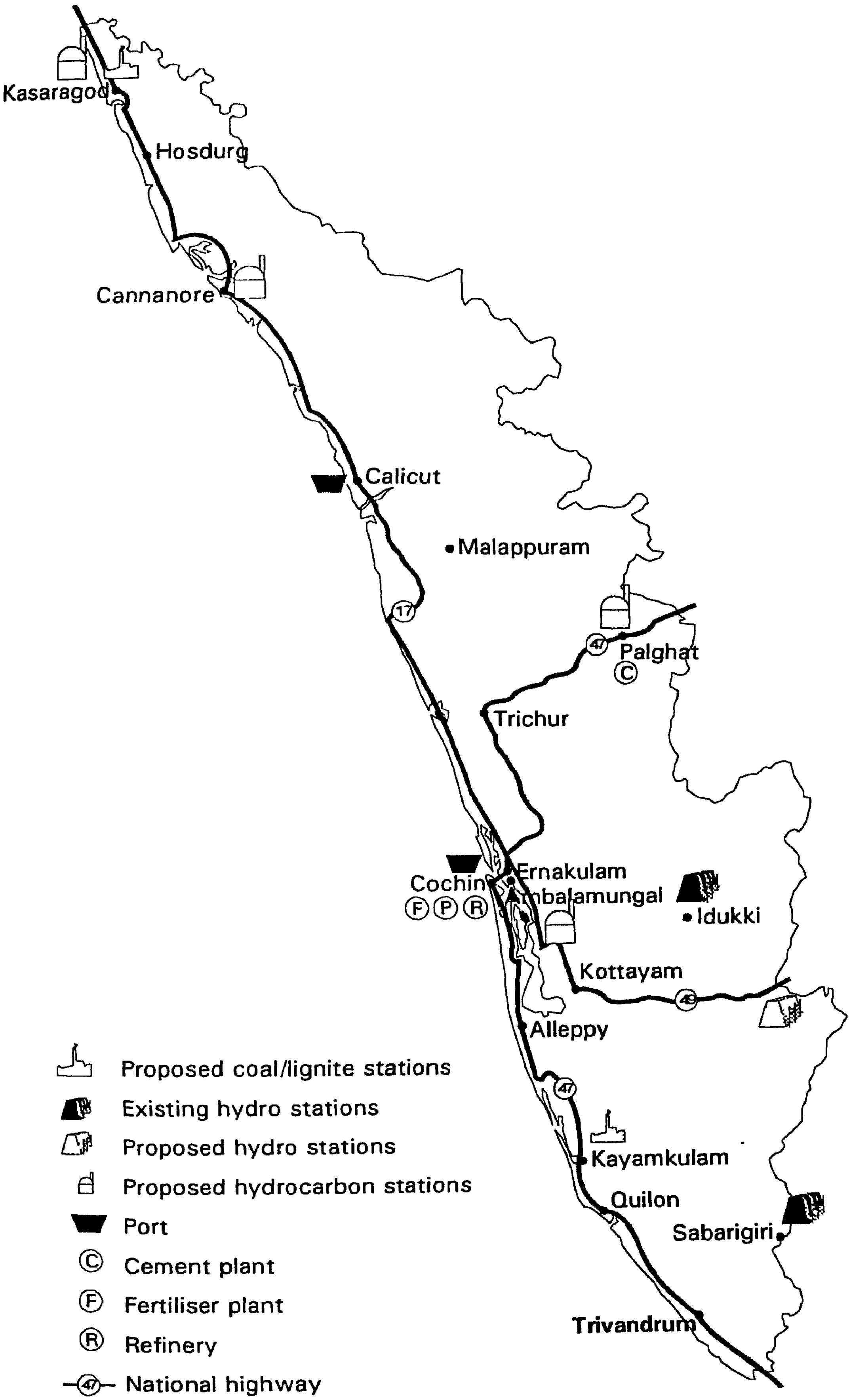
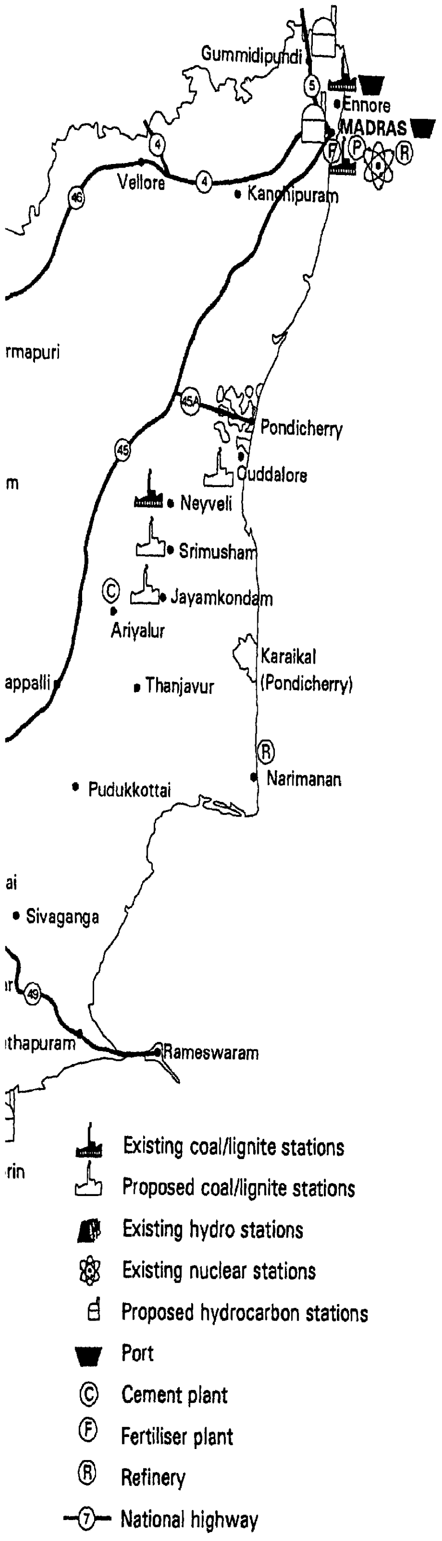


Figure 6.3: Map of Kerala



d LNG Terminal Options



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6.2.1. Potential LNG requirements

The gas requirement for a power plant has been taken as 1.04 million cubic meter (MCM) per year for every megawatt of installed capacity, assuming a plant load factor of 68.5% and the calorific value of gas as 8760 kilo calories/Nm^3.

The lower limit for the gas requirement has been derived from the installed capacities of the power stations committed to using gas.

The upper limit for natural gas requirement has been derived as per the following:

1. Since power stations using gas oil, fuel oil or naphtha can switch to using gas without major modifications, it has been assumed that all power stations using these fuels would switch to gas if it was made available at a competitive price.
2. The Ministry of Coal in its IX Plan Document has estimated that only 55% of the coal requirement of the power sector in South India will be met in the year 2001. It has been assumed that this situation of shortages will continue till 2015. To meet the requirements of the balance (coal based) capacities, options would be either imported coal or gas. The planned coal based capacity amenable to a fuel switch would therefore be about 45% of the additions in the period 2005-15 (considering the lead time required to make LNG available). This would amount to 2655 MW (45% of 5900) of capacity which could use natural gas instead of imported coal.

The potential for sale of natural gas in the power sector in the three states is summarised in Table 6.1. while the same for other industries is shown in Table 6.2.

Table 6.1: Natural gas sales potential in the power sector

(MCM/year)

	Lower limit	Upper limit
Karnataka		
2000	0	931
2005	42	1282
2010	354	2437
2015	354	2905
Kerala		
2000	0	0
2005	62	158
2010	582	1475
2015	1102	3308
Tamil Nadu		
2000	140	140
2005	484	900
2010	2044	3439
2015	3604	5917
All three states		
2000	140	1071
2005	588	2340
2010	2980	7351
2015	5060	12130

Table 6.2: Natural gas sales potential in industries

(BCM/year)

Industry	Karnataka		Kerala		Tamil Nadu	
	Existing	Future	Existing	Future	Existing	Future
Cement	0.551	2.105	0.040	0.040	0.535	0.697
Fertiliser	0.235	0.235	0.160	0.360	0.565	0.565
Iron & Steel	0.098	2.905	0.000	0.000	0.000	0.000
Petrochemical	0.000	0.000	0.169	0.169	0.108	0.108
TOTAL	**0.884**	**5.245**	**0.369**	**0.569**	**1.208**	**1.370**

For both power and other industries taken together, there exists a sales potential for natural gas in the range of 12.24 - 19.31 BCM/year. This translates to an LNG requirement of 8.9 - 14.1 million tons per year in 2015 (using a conversion factor of 0.73 MMT of LNG per BCM of natural gas).

6.3. SITING OF AN LNG TERMINAL AND POSSIBLE ALIGNMENT OF A GAS PIPELINE

An integrated examination of the likely large demand centres of the three states suggest the following possible locations for an LNG terminal and regassification plant.

1. **Mangalore, Kasargod area**: This would be in close proximity to the demand centres in and around Mangalore (Karnataka) and Kasargod (Kerala). However, inland demand centres i.e. Bellary, Raichur and Gulberga (590 km from Mangalore) are relatively far away and the economics of laying a pipeline to feed these inland locations would require a detailed techno-economic evaluation. (If found feasible, the line could later be extended into Andhra Pradesh). This line would have to cross the Western Ghats shortly after leaving the coastal plains near Mangalore.

The Hindustan Petroleum Corporation (HPCL) is erecting a large LPG storage facility (22 X 1350 tonnes pressurised spheres) at Mangalore to receive imported LPG with a capacity of 600,000 MMT per annum. Tankers will berth at the existing oil jetty of Mangalore Port Trust (draft around 9.5 m)

The Mangalore Refinery and Petrochemicals Ltd (MRPL) have early this year commissioned a 60,000 b/d refinery and it is intended to increase its capacity to 180,000 b/d. As the existing jetty has a low draft, a new jetty with a draft of 15.5 m is being erected to receive Long Range II vessels and also partly loaded (upto 120,000 MMT) Suezmax vessels.

2. **Cochin area**: The demand immediately in and around Cochin is estimated to be considerably lower than the Mangalore/Kasargod region. However, there is a gap between the Western Ghats and the Annamalai Hills which will facilitate laying a gas pipeline from Cochin through the gap at Palghat and onto Coimbatore and Bangalore. Although the projected demand at these two centres is not high, it is interesting to note that when the Hazira-Bijaipur-Jagdishpur (HBJ) pipeline (India's only inter-state gas pipeline) was laid across west and north India, the position of thermal power stations and fertiliser was decided more by the proposed alignment of the pipeline than visa-versa. A coastal pipeline linking the Mangalore/Kasargod area to the Cochin area (either way) could also be considered.

The Cochin refinery has a capacity of 150,000 b/d. At the crude oil terminal the present draft of just under 11m allows receipt of between 35,000 MMT and 59,000 MMT crude cargoes. During the monsoon months the draft reduces to 10.36 m.

3. **Madras/Ennore area**: This area has also been identified as a large demand centre. The Madras Refinery (MRL) of capacity 130,000 b/d receives crude at 2 jetties of the Madras Port Trust with draft of 14.63 m and 16.15 m. Barring VLCCs, all types of vessels can be handled at these jetties. However, the jetty occupancy is very high at 84% and availability of land in the port area is almost ruled out.

The satellite port of Ennore is north of Madras. It has been primarily set up to handle coal imports for TNEB's thermal power station. The port at maximum capacity can handle 8.9 Mmtpa of coal.

The port may in future provide berthing facilities for petrochemical products and petroleum. A tentative estimate of Rs 2.03 billion has been earmarked for satellite port development works. IOC and Petronas/MRL have indicated their interest in constructing an LPG import terminal at Ennore.

Shell's requirement for an LNG terminal have been noted i.e. a draft availability of 13.5 m, a 25 hectare site with a buffer zone from other installations of between 400 m and 2000 m and a distance from residential areas of between 2 - 5 km. This would almost certainly indicate that LNG tanker receipt and terminal facilities cannot be erected at any of the existing ports and a captive LNG jetty would have to be constructed. Generally, drafts on the eastern coast are deeper than on the west coast. To meet a draft of 13.5 m on the west coast, round-the-year dredging may be required. Also, it must be remembered that coastal areas, particularly, Kerala are heavily populated and safety distances to the extent indicated may need to be reduced.

APPENDICES

Appendix 2.1: New power projects expected in Karnataka

KARNATAKA
Year 2000

S. No.	Location	Capacity MW	Fuel	Promoter	Total Cap. MW	Status
1.	Mangalore	250	Coal	Cogentrix	1000	All clearances
2.	Raichur	210	Coal	Karnataka Power Corporation	420	All clearances
3.	Gerusoppa	60	Hydro	Karnataka Power Corporation	240	All clearances
4.	Kadra	50	Hydro	Karnataka Power Corporation	150	All clearances
5.	Shivpur	18	Hydro	SEB	18	
6.	Brindavan	12	Hydro	Karnataka Power Corporation	12	
7.	Mallapur	3.5	Hydro	SEB	7.5	
8.	Kaiga	110	Nuclear	Nuclear Power Corporation	440	Construction
9.	Mangalore	163	Fuel Oil	Smith Cogeneration	163	PPA signed
10.	Malpe	150	Fuel Oil	Euro Capital, Germany	150	PPA signed
11.	Mangalore	150	Fuel Oil	Universal Water and Power, Canada	150	PPA signed
12.	Kumta	110	Fuel Oil	Universal Water and Power, Canada	110	PPA signed
	SMALL FAST TRACK PROJECTS					
13.	Tumkur	32.5 *	Fuel Oil	DLF		
14.	Doddaballapur	45 *	Fuel Oil	Raunaq		
15.	Hoskote	39.8 *	Fuel Oil	Scintilla Software		
16.	Bellary	27.8 *	Fuel Oil	Rayalaseema		
17	Pillaguppa	22.5 *	Fuel Oil	Raunaq		
18	Hosadurga	39.8 *	Fuel Oil	Scintilla Software		
19	Chickballapur	22.5 *	Fuel Oil	Raunaq		
20.	Indi	27.8 *	Fuel Oil	Rayalaseema		
21.	Dharwar	51.9 *	Naphtha	Gujarat Fluoro Chem		
22	Wadi	48.8 *	Naphtha	Bhoruka Power		
23	Bellary	50.8 *	Naphtha	Bharat Forge		
24	Harihar	38 *	Naphtha	Ask Brothers		
25.	Nanjangud	38 *	Naphtha	Ask Brothers		
	Est of available cap.	194.1				
		1480.6				

* Note
1 About 40% of the small fast track projects are expected to materialise.
2 Of those which materialise, approximately half would be using FO, and the others naphtha.

Appendix 2.1

KARNATAKA
Year 2005

S. No.	Location	Capacity MW	Fuel	Promoter	Total Cap. MW	Status
1.	Mangalore	750	Coal	Cogentrix	1000	All clearances
2	Raichur	210	Coal	Karnataka Power Corporation	420	All clearances
3.	Torangallu	260	Coal	Jindal/Tractbel Power	260	TEC
4.	Gerusoppa	60	Hydro	Karnataka Power Corporation	240	All clearances
5.	Kadra	50	Hydro	Karnataka Power Corporation	150	All clearances
6.	Kodasalli	40	Hydro	Karnataka Power Corporation	120	All clearances
7.	Bhadra	6	Hydro	Karnataka Power Corporation	6	All clearances
8.	Kaiga	110	Nuclear	Nuclear Power Corporation	440	All clearances
9.	Hoody	40	Gas	Khoday India	40	
	FUEL OIL BASED PROJECTS					
10.	Hassan	200 *	Fuel Oil	Hassan Power		
11.	Mandya	145 *	Fuel Oil	Mandya Power Partners		
12.	Bidar	100 *	Fuel Oil	HMG Power		
13.	Indi	100 *	Fuel Oil	HMG Power		
14.	Jam Khandi	100 *	Fuel Oil	HMG Power		
15.	Kolar	100 *	Fuel Oil	HMG Power		
	Est. of available cap.	298				
		1824				

* Note: 1. About 40% of the fuel oil based projects are expected to materialise.
2. TEC = Techno-economic clearance

KARNATAKA
Year 2010

S. No.	Location	Capacity MW	Fuel	Promoter	Total Cap. MW	Status
1.	Kaiga Extn.	110	Nuclear	Nuclear Power Corporation	440	IPC
2.	Bijapur	150	Naphtha	KEI Energy	150	IPC
3.	Nanjangud	110	Naphtha	Independent Power Services	110	IPC
4.	Bangalore	100	Naphtha	Peenya Power	100	
5	Gerusoppa	120	Hydro	Karnataka Power Corporation	240	IPC
6	Sharavati Tailrace	120	Hydro	Karnataka Power Corporation	240	IPC
7.	Kodasalli	80	Hydro	Karnataka Power Corporation	120	IPC
8	Kadra	50	Hydro	Karnataka Power Corporation	150	IPC
9	Bidadi	300	Gas	Karnataka Power Corporation	300	IPC
10.	Mangalore	500	Coal	Nagarjuna Chemicals & Fertilisers	1000	
11.	Hospet	250	Coal	Deccan Power	500	
12	Mysore	250	Coal	Mysore Power	500	
	SMALL HYDRO IPPs					
13.	Keerthe Hole	21 *	Hydro	Subhash Project & Marketing		
14	Kabini	20 *	Hydro	Subhash Project & Marketing		
15	Tunga Anecut	20 *	Hydro	Dandeli Steel & Ferro Alloys		
16.	Chunchanakatte	15 *	Hydro	Graphite India		
17	Hemavathi	15 *	Hydro	Sandhur Manganese & Iron Ore		
18	Varahi	15 *	Hydro	Bhoruka Power		
19	Varahi Tailrace	15 *	Hydro	Sandhur Manganese & Iron Ore		
20	Anandka	9 *	Hydro	Arvind Mills		
21	Narayanpur	9 *	Hydro	Murdeswara Power		
22	Ceevy	6.5 *	Hydro	Mathew Charayel		
23	Harangi	4.5 *	Hydro	North East Energy Services		
24	Upper Kaneri	3.5 *	Hydro	Gujarat Spinner		
	Est of available cap	61.4				
		2201.4				

* Note 1 About 40% of the small hydro IPPs are expected to materialise.

2 IPC = In-principal clearance This is a very preliminary type of clearance by the CEA, which just says that at first sight, the project seems viable, and it would be worthwhile to prepare the detailed project report.

Appendix 2.1

KARNATAKA
Year 2015

S. No.	Location	Capacity MW	Fuel	Promoter	Total Cap. MW	Status
1.	Mangalore	500	Coal	Nagarjuna Chemicals & Fertilisers	1000	
2.	Hospet	250	Coal	Deccan Power	500	
3.	Mysore	250	Coal	Mysore Power	500	
4.	Kalindi II	120	Hydro	Karnataka Power Corporation	270	IPC
5.	Sharavati Tailrace	120	Hydro	Karnataka Power Corporation	240	IPC
6.	Gangawali	105	Hydro	Karnataka Power Corporation	210	IPC
7.	Kaiga Extn.	110	Nuclear	Nuclear Power Corporation	440	IPC
		1455				

* Note: IPC = In-principal clearance. This is a very preliminary type of clearance by the CEA, which just says that at first sight, the project seems viable, and it would be worthwhile to prepare the detailed project report.

Appendix 2.2: New power projects expected in Kerala

KERALA
Year 2000

S. No.	Location	Capacity MW	Fuel	Promoter	Total Cap. MW	Status
1.	Lower Periyar	180	Hydro	Kerala State Electricity Board	180	
2.	Kakkad	25	Hydro	Kerala State Electricity Board	25	
3.	Kayamkulam	200	Coal	National Thermal Power Corporation	400	Construction
4.	Kaiga	15	Nuclear	Nuclear Power Corporation	440	Construction
	SMALL HYDRO IPPs					
5.	Kuthungal	20 *	Hydro	Indsil Electrosaeets		
6.	Bhoothanketu	16 *	Hydro	Silcal Metalurgic		
7.	Karikkayam	12 *	Hydro	Travancore Electro Chemical Industries		
8.	Barapole	9 *	Hydro	Ideal Projects and Services		
9.	Anakkayam	8 *	Hydro	Ideal Projects and Services		
10.	Chathankkottunada - II	7 *	Hydro	Ideal Projects and Services		
11.	Chembukkadavu - II	7 *	Hydro	Ideal Projects and Services		
12.	Vilangad	7 *	Hydro	Ideal Projects and Services		
13.	Ullunkal	6 *	Hydro	Travancore Electro Chemical Industries		
14.	Western Kallar	5 *	Hydro	Ideal Projects and Services/Canadian Hydro		
15.	Palchuram	3.5 *	Hydro	Ideal Projects and Services		
	Est. of available cap.	40.2				
		460.2				

* Note About 40% of the small hydro IPPs are expected to materialise.

Appendix 2.2

KERALA
Year 2005

S. No.	Location	Capacity MW	Fuel	Promoter	Total Cap. MW	Status
1.	Kayamkulam	200	Coal	National Thermal Power Corporation	400	Construction
2.	Kasargod	60	Gas	Kasargod Power Corporation	60	IPC
3.	Muvattypuzha	7	Hydro	Kerala State Electricity Board	7	
4.	Peppara	3	Hydro	Kerala State Electricity Board	3	
5.	Kaiga	15	Nuclear	Nuclear Power Corporation	440	Construction
6.	Ambalamugal	500	Vacuum Res.	Cochin Refineries	500	IPC
	FUEL OIL BASED PROJECTS					
7.	Kahjikhode	100 *	Fuel Oil	W I Services & Estates		
8.	Viniyam	25.9 *	Fuel Oil	NA		
9.	Mundakep	25 9 *	Fuel Oil	NA		
10.	Perundalmanna	25.9 *	Fuel Oil	NA		
11.	Nilambur	25.9 *	Fuel Oil	NA		
12.	Kuttinatur	25.9 *	Fuel Oil	NA		
	Est. of available cap	91.8				
		876.8				

* Note: 1. About 40% of the fuel oil based projects are expected to materialise.
2. 'NA' indicates that the information was not available.
3. IPC = In-principal clearance. This is a very preliminary type of clearance by the CEA, which just says that at first sight, the project seems viable, and it would be worthwhile to prepare the detailed project report.

KERALA
Year 2010

S. No.	Location	Capacity MW	Fuel	Promoter	Total Cap. MW	Status
1.	Kasargod	195	Coal	Kasargod Power Corporation	778	
2.	Kasargod	500	Gas	Finolex Energy Corporation	1000	IPC
3.	Puyankutty	120	Hydro	Kerala State Electricity Board	120	
4.	Kottukal	348	Naphtha	Kumars Energy Corporation	348	IPC
5.	Palghat	330	Naphtha	Palakkad Power/EDC International	330	IPC
6	Kaiga Extn.	15	Nuclear	Nuclear Power Corporation	440	IPC
		1508.0				

* Note: IPC = In-principal clearance This is a very preliminary type of clearance by the CEA, which just says that at first sight, the project seems viable, and it would be worthwhile to prepare the detailed project report.

Appendix 2.2

KERALA
Year 2015

S. No.	Location	Capacity MW	Fuel	Promoter	Total Cap. MW	Status
1.	Kasargod	585	Coal	Kasargod Power Corporation	778	
2.	Kasargod	500	Gas	Finolex Energy Corporation	1000	IPC
3.	Kannur	500	Naphtha	KPP Nambiar & Associates	500	IPC
4.	Kasargod	500	Naphtha	BPL Group	500	IPC
5.	Kaiga Extn.	15	Nuclear	Nuclear Power Corporation	440	IPC
		2100.0				

* Note: IPC = In-principal clearance. This is a very preliminary type of clearance by the CEA, which just says that at first sight, the project seems viable, and it would be worthwhile to prepare the detailed project report.

Appendix 2.3: New power projects expected in Tamil Nadu

TAMIL NADU
Year 2000

S. No.	Location	Capacity MW	Fuel	Promoter	Total Cap. MW	Status
1.	North Madras	210	Coal	Tamil Nadu Electricity Board	210	Construction
2.	Basin Bridge	120	Gas	Tamil Nadu Electricity Board	120	Construction
3.	Narimanam	5	Gas	Tamil Nadu Electricity Board	5	
4.	Kaiga	30	Nuclear	Nuclear Power Corporation	440	Construction
		365.0				

Appendix 2.3

TAMIL NADU
Year 2005

S. No.	Location	Capacity MW	Fuel	Promoter	Total Cap. MW	Status
1.	North Madras II	1050	Coal	Videocon International	1050	TEC
2.	Various locations *	400	Fuel Oil	Various IPPs	* 40% of proposals aggregating about 1000 MW are estimated to materialise	
3.	Pillai Peru Malnallur	330	Gas	Dyna Vision/J Makowski	330	TEC
4.	Kundh	30	Hydro	Tamil Nadu Electricity Board	30	
5.	Periyarvagai	10	Hydro	Silcal Industries	10	
6.	Lower Bhavani	8	Hydro	Tamil Nadu Electricity Board	8	
7.	Sathanur	7.5	Hydro	Tamil Nadu Electricity Board	7.5	
8.	Neyveli Zero Unit	250	Lignite	S I Power Systems	250	TEC
9.	Kaiga	30	Nuclear	Nuclear Power Corporation	440	Construction
10.	Various locations	100	Wind	TNEB and various IPPs	100	
		2215.5				

* Note: TEC = Techno-economic clearance

Appendix 2.3

TAMIL NADU
Year 2010

S. No.	Location	Capacity MW	Fuel	Promoter	Total Cap. MW	Status
1.	Cuddalore	660	Coal	Cuddalore Power Company	1320	IPC
2.	North Madras	500	Coal	Tri-Sakhthi Energy	500	IPC
3.	Basin Bridge	220	Fuel Oil	GMR Yasavi Power	220	IPC
4.	Samalpatti	100	Fuel Oil	SIY Industries	100	IPC
5.	Somayanallur	100	Fuel Oil	Balaji Power	100	IPC
6.	Gummidipoondi	1000	Gas	GYX Industries	1000	IPC
7.	Vembar	500	Gas	Indian Power Projects	2000	IPC
8.	Pykara	150	Hydro	Tamil Nadu Electricity Board	150	
9.	Kaiga Extn.	30	Nuclear	Nuclear Power Corporation	440	IPC
		3260.0				

* Note IPC = In-principal clearance. This is a very preliminary type of clearance by the CEA, which just says that at first sight, the project seems viable, and it would be worthwhile to prepare the detailed project report.

Appendix 2.3

TAMIL NADU
Year 2015

S. No.	Location	Capacity MW	Fuel	Promoter	Total Cap. MW	Status
1.	Cuddalore	660	Coal	Cuddalore Power Company	1320	IPC
2.	Tuticorin	500	Coal	SPIC Elec. Power Corporation	500	IPC
3.	Vembar	1500	Gas	Indian Power Projects	2000	IPC
4.	Jayamkondam	550	Lignite	McNally Bharat/Tamil Nadu Ind. Dev. Corpn.	550	IPC
5.	Srimusham	250	Lignite	TICAPCO/GM Swamy Associates	250	IPC
6.	Kaiga Extn.	30	Nuclear	Nuclear Power Corporation	440	IPC
		3490.0				

* Note: IPC = In-principal clearance. This is a very preliminary type of clearance by the CEA, which just says that at first sight, the project seems viable, and it would be worthwhile to prepare the detailed project report.

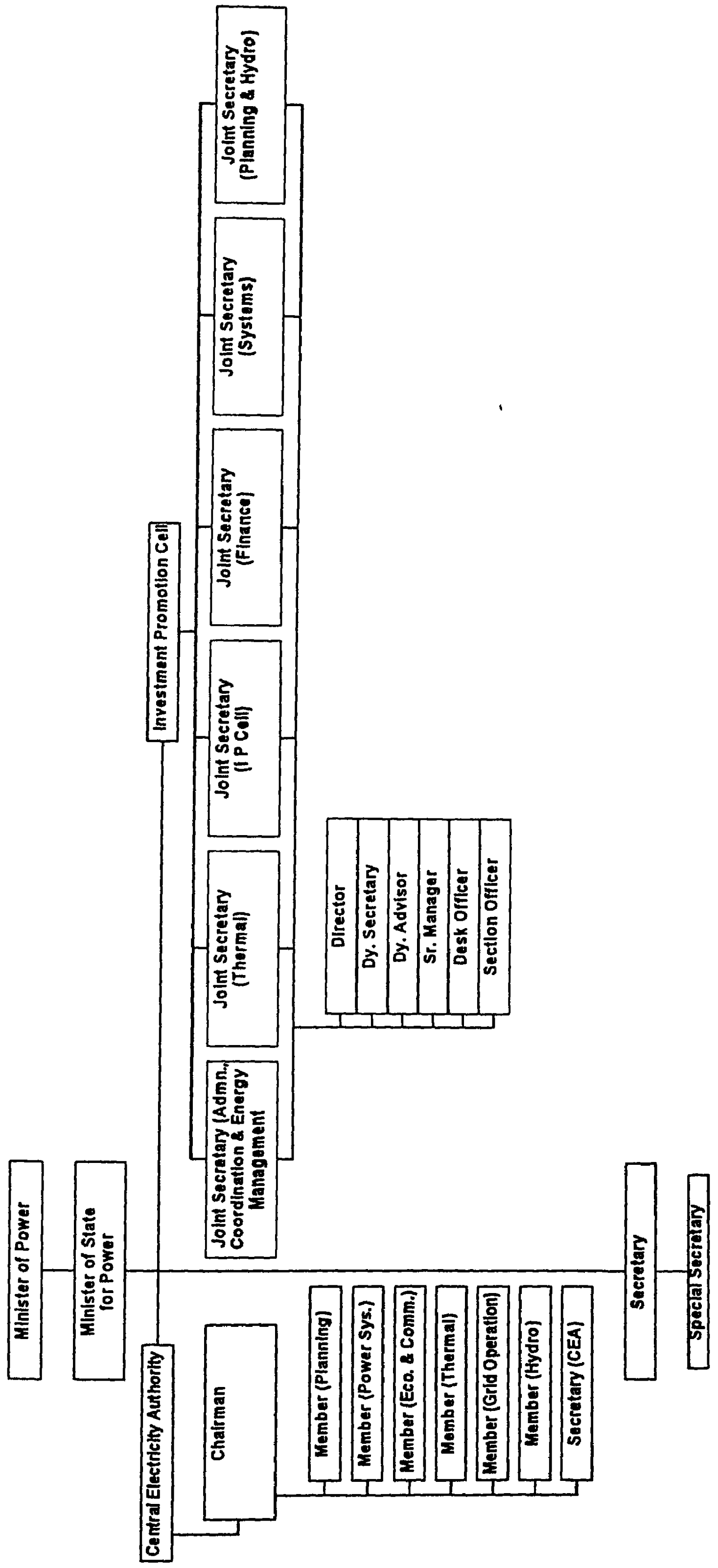
Appendix 2.4: Consolidated list of IPPs

Sl.No	Name of Project	Capacity	Type	Status	Name of company
Karnataka					
1	Mangalore TPS	1000	Coal	IPC	NAGARJUNA CHEMICALS & FERTILISERS LTD.
2	ANKOLA KOMTA (HOSPET	500	COAL	IPC	DECCAN POWER CORPN. LTD.
3	MYSORE TPS	500	COAL	IPC	MYSORE POWER GEN.
4	HASSAN	200	DIESEL	IPC	HASAN POWER CO. LTD.
5	Thubinakere (Mandya)	145	Diesel	IPC	Mandya Power Partners
6	Bidar	100	Diesel	IPC	HMG Power Ltd.
7	INDI	100	Diesel	IPC	HMG Power Ltd.
8	Jam Khandi	100	Diesel	IPC	HMG Power Ltd.
9	Kolar	100	Diesel		HMG Power Ltd.
10	Hoody	40	GAS		Khoday India Ltd.
11	TORANGALLU	260	COAL	TEC	JINDAL/TRACTBEL POWER CO. LTD.
12	BIDADI CCPP	300	GAS	IPC	KARNATAKA POWER CORPN. LTD.
13	ALMATTI N. THANMAKAL	1107	Hydro	IPC	CHAMUNDI POWER CO. LTD.
14	Keerthe Hole	21	Hydro		M/s. Subhash Project & Marketing Ltd.
15	Kabini DPH	20	Hydro		M/s. Subhash Project & Marketing Ltd.
16	Tunga Anecut	20	Hydro		M/s. Dandeli Steel & Ferro Alloys Ltd.
17	Chunchanakatte	15	Hydro		M/s. Graphite India Ltd.
18	Hemavathy LBC	15	Hydro		M/s. Sandhur Magnese & Iron Ore Ltd.
19	Varahi IDPH	15	Hydro		M/s. Bhoruka Power Corporation Ltd.
20	Varahi Tail Race	15	Hydro		M/s. Sandhur Magnese & Iron Ore Ltd.
21	Anandka HEP	9	Hydro		Arvind Mills, Ahmedabad
22	Narayanpur LBC HEP	9	Hydro		Murdeswara Power Corporation Ltd.
23	Ceevy MHS	6.5	Hydro		C.V. Mathew Charayel, Mysore
24	Harangi LBC HEP	4.5	Hydro		North East Energy Services, USA
25	Upper Kaneri HEP	3.5	Hydro		Gujarat Spinner Co.
26	Mangalore TPS	1000	Imp. Coal	TEC	Mangalore Power Co. (Cogentrix Inc, USA)
27	NANJANGUDUA	110	NAPTHA	IPC	INDEPENDENT POWER SERVICES CO., USA
28	BANGALORE CCPP	100	NAPTHA	IPC	PEENYA POWER CO. LTD.
29	Bijapur	150	NAPTHA	IPC	Kei Energy Ltd., Hyderabad
	Total 29	5965.5			
Kerala					
30	Kasargod TPC	778	Coal		M/s. Kasargod Power Corporation Ltd.
31	Kasargod	60	Gas	IPC	Kasargod Power Corporation Ltd. (M/s.RPG)
32	Kasargod	1000	Gas	IPC	Finolex Energy Corporation Ltd.
33	Kuthungal HEP	20	Hydro		Indsil Electrosaeets Ltd.
34	Boothathankettu	16	Hydro		Silcal Metalurgic (P) Ltd.
35	Karikkayam HEP	12	Hydro		Travancore Electro Chemical Indus.Ltd.
36	Barapole HEP	9	Hydro		Ideal Projects and Services Pvt.Ltd.
37	Anakkayam HEP	8	Hydro		Ideal Project & Services (P) Ltd.
38	Chathankkottunada-II	7	Hydro		Ideal Project & Services (P) Ltd.
39	Chembukkadavu-II	7	Hydro		Ideal Projects & Services (P) Ltd.
40	Vilangad HEP	7	Hydro		Ideal Project & Industries (P) Ltd.
41	Ullunkal HEP	6	Hydro		Travancore Electric Chemical Ind.Ltd.
42	Western Kallar HEP	5	Hydro		Ideal Projects & Services & Canadian Hydro Dev.
43	Palchuram HEP	3.5	Hydro		Ideal Projects & Services (P) Ltd.
44	KANJIKODE DGPP	100	LSHS	IPC	W I SERVICES & ESTATES LTD., DELHI
45	Kannur CCGT	500	Naptha	IPC	M/s. KPP Nambiar & Associates
46	Kottvkal	348	Naptha	IPC	Kumars Energy Corporation
47	Palakkad	330	Naptha	IPC	Palakkad Power Generating Co./Ensearch Intl.ltd
48	Vypeen	650	Naptha		Siasin Energy Pvt.Ltd.
49	Cheemeni TPP	500	Naptha	IPC	BPL Group
50	Ambalamugal	500	Vacum Res.	IPC	M/s. Cochin Refineries Ltd.
	Total 21	4866.5			

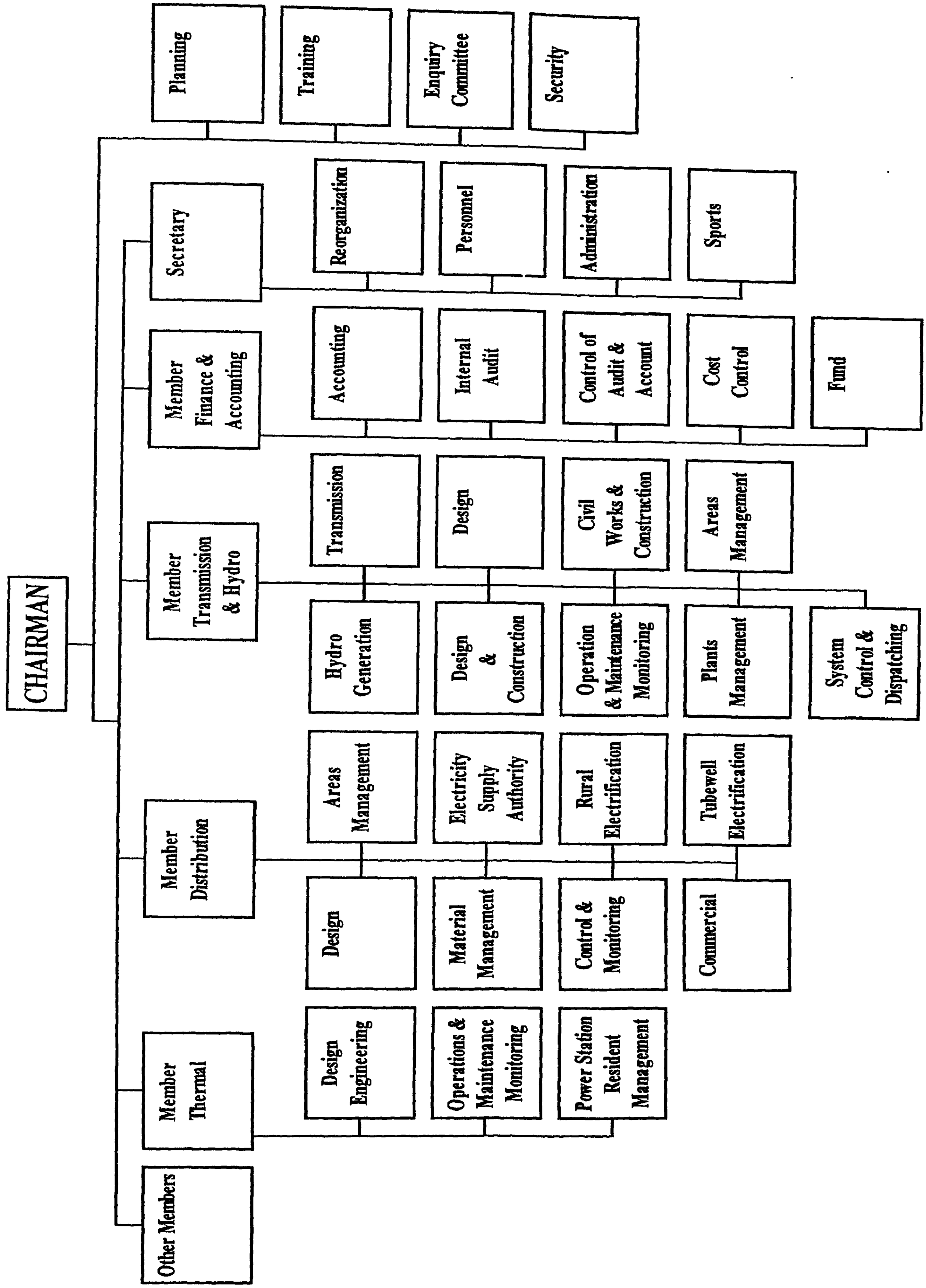
Appendix 2.4

Sl.No	Name of Project	Capacity	Type	Status	Name of company
TAMIL NADU					
51	Cuddalore IPS	1320	COAL	IPC	Cuddalore Power Company Ltd.
52	North Madras II	1050	COAL	TEC	M/s Videocon International Ltd., Bombay
53	North Madras TPP III	500	COAL	IPC	M/s Tri-Sakthi Energy Pvt Ltd., Madras
54	Tuticorin IV TPS	500	COAL	IPC	M/s SPIC Elec Power Corp. Ltd. Madras
55	Samayanallur DEPP	100	FO	IPC	M/s Balaji Power Corp. Pvt. Ltd.
56	Basin Bridge Stage-II	220	FO	IPC	G M R Yasavi Power Corporation Ltd.
57	Gummidi Poondi	1000	GAS	IPC	M/s GYX Industries
58	Pillai Peru Malnallur	330.5	GAS	TEC	Dyna Vision of Reddy Group/J. Makowski, USA
59	Vembar TPP	2000	GAS	IPC	M/s Indian Power Projects Ltd., Madras
60	Periyarvagai HEP	10	Hydro		M/s Silcal Industries Ltd., Coimbatore
61	Jayamkondam Lignite PP	550	LIGNITE	IPC	Mcnally Bhart Engg. Co Ltd & TIDCO., J V
62	Srimushnam Lignite	250	LIGNITE	IPC	TICAPCO, GM Swamy Associates
63	Zero Unit (NLC)	250	LIGNITE	TEC	SI Power Systems Inc., USA
64	Samal Patti DEPP	100	LIGNITE	IPC	M/s SIY Industries Ltd., Coimbatore
65	Relocation TPS	1380	THERMAL	IPC	HMZ Power Ltd.
	Total 15	9560.5			

Appendix 3.1: Ministry of Power - Simplified organisation chart

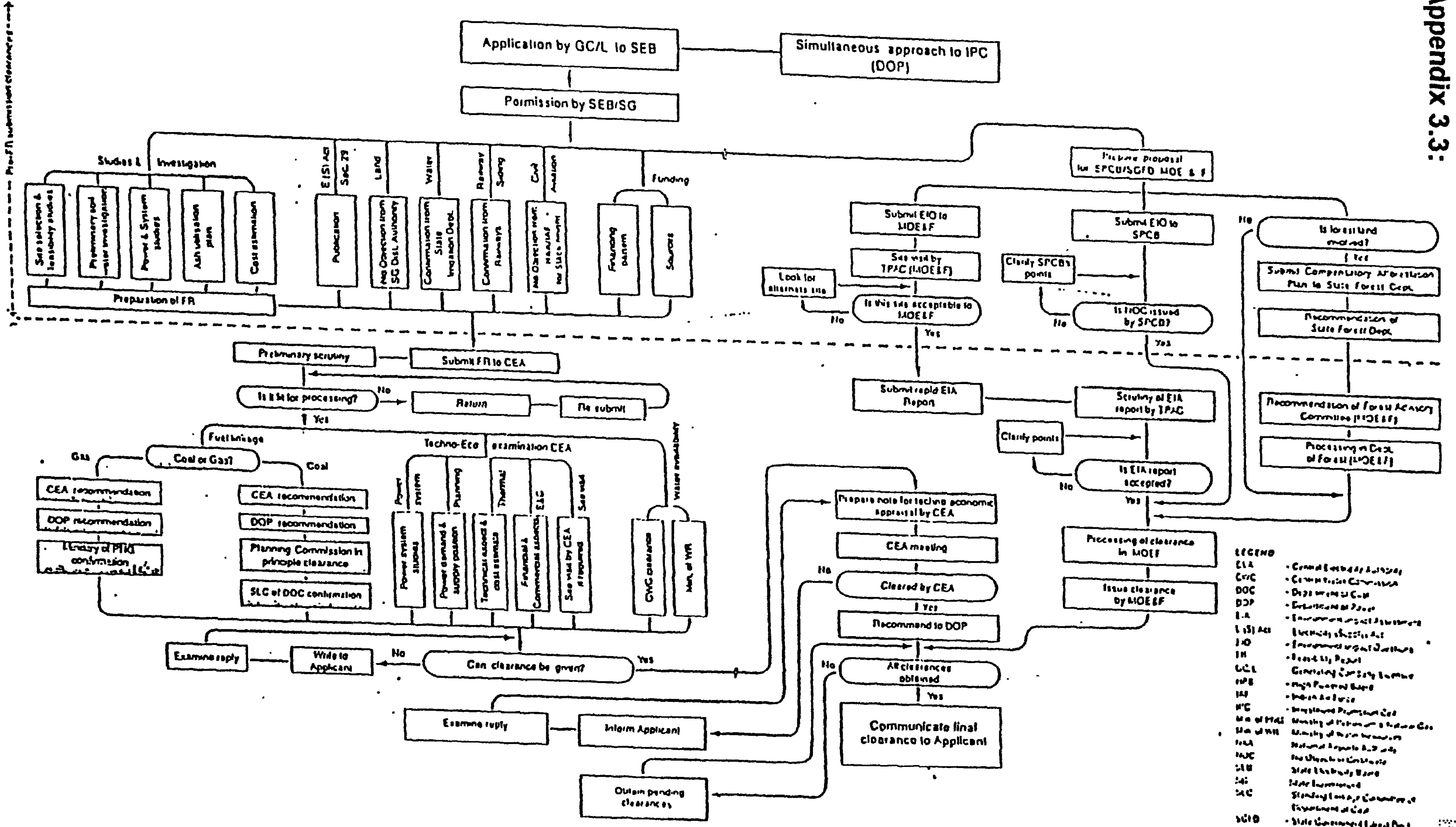

Minister of Power
Minister of State for Power
Secretary
Special Secretary
Investment Promotion Cell
Joint Secretary (Admn., Coordination & Energy Management
Joint Secretary (Thermal)
Joint Secretary (I P Cell)
Joint Secretary (Finance)
Joint Secretary (Systems)
Joint Secretary (Planning & Hydro)
Director
Dy. Secretary
Dy. Advisor
Sr. Manager
Desk Officer
Section Officer
Central Electricity Authority
Chairman
Member (Planning)
Member (Power Sys.)
Member (Eco. & Comm.)
Member (Thermal)
Member (Grid Operation)
Member (Hydro)
Secretary (CEA)

Appendix 3.2: Organisation chart for an SEB



Appendix 3.3:

TECHNO-ECONOMIC APPRAISAL OF THERMAL POWER PROJECTS—FLOW CHART


Application by GC/L to SEB
Simultaneous approach to IPC (DOP)
Permission by SEB/SG
Pre-FR submission clearances
Studies & Investigation
Site selection & feasibility studies
Preliminary soil water investigation
Power & System studies
Ash utilisation plan
Cost estimation
Preparation of FR
E (S) Act
Sec. 29
Publication
Land
No Objection from SG Distt. Authority
Water
Confirmation from State Irrigation Deptt.
Railway
Siding
Confirmation from Railways
Civil
Aviation
No Objection from NAA/IAF for Stack height
Funding
Financing pattern
Sources
Picture proposal for SPCB/SGFD MOE & F
Submit EIQ to MOE&F
Site visit by TPAC (MOE&F)
Look for alternate site
Is this site acceptable to MOE&F
No
Yes
Submit EIQ to SPCB
Clarify SPCB's points
Is NOC issued by SPCB?
No
Yes
Is forest land involved?
No
Yes
Submit Compensatory Afforestation Plan to State Forest Deptt.
Recommendation of State Forest Deptt.
Recommendation of Forest Advisory Committee (MOE&F)
Processing in Deptt. of Forest (MOE&F)
Submit rapid EIA Report
Scrutiny of EIA report by TPAC
Clarify points
Is EIA report accepted?
No
Yes
Processing of clearance in MOEF
Issue clearance by MOE&F
Preliminary scrutiny
Submit FR to CEA
Is it fit for processing?
No
Return
Re submit
Yes
Fuel linkage
Coal or Gas?
Gas
CEA recommendation
DOP recommendation
Ministry of PNG confirmation
Coal
CEA recommendation
DOP recommendation
Planning Commission in principle clearance
SLC of DOC confirmation
Techno-Eco examination CEA
Power system
Power system studies
Planning
Power demand & supply position
Thermal
Technical aspect & cost estimates
E&C
Financial & Commercial aspects
Site visit
Site visit by CEA if required
Water availability
CWC clearance
Min. of WR
Can clearance be given?
No
Write to Applicant
Examine reply
Yes
Prepare note for techno economic appraisal by CEA
CEA meeting
Cleared by CEA
No
Yes
Recommend to DOP
All clearances obtained
No
Yes
Communicate final clearance to Applicant
Examine reply
Inform Applicant
Obtain pending clearances
LEGEND
CEA - Central Electricity Authority
CWC - Central Water Commission
DOC - Department of Coal
DOP - Department of Power
EIA - Environmental Impact Assessment
E(S) Act - Electricity (Supply) Act
EIQ - Environmental Impact Questionnaire
FR - Feasibility Report
GC/L - Generating Company/Licensee
HPB - High Powered Board
IAF - Indian Air Force
IPC - Investment Promotion Cell
Min of P&NG - Ministry of Petroleum & Natural Gas
Min of WR - Ministry of Water Resources
NAA - National Airports Authority
NOC - No Objection Certificate
SEB - State Electricity Board
SG - State Government
SLC - Standing Linkage Committee of Department of Coal
SGFD - State Government Forest Dept
SPCB - State Pollution Control Board

Appendix 3.4 Clearances Required for Power Projects - Detailed Procedures

Sl. No.	Item	Agency	Remarks
STATUTORY CLEARANCES			
1.	**COST ESTIMATES** Any Power project involving capital expenditure exceeding the limit by Govt. (currently Rs 400 crore for competitively bid projects, Rs 100 crores otherwise) needs to be scrutinized by CEA for examination of salient features and benefits which may accrue therefrom.	CEA	Required under Section 29 of Electricity (Supply) Act, 1948 (E(S) Act, 1948).
2.	**TECHNO-ECONOMIC CLEARANCE/CONCURRENCE OF CEA:** By CEA after examination of (i) River works/dams to be put up for hydro and for water availability for thermal plants. (ii) Greatest possible economic output of electric power. (iii) Transmission lines and Systems (iv) Reasonableness of the Scheme (v) Site location for optimum utilization of fuel resources, distance from load centers, transportation facilities, water availability and environmental considerations.	CEA	Under section 30 of Electricity (Supply) Act, 1948. SEBs, State Govts, concerned Ministries of Coal, Petroleum & Natural Gas, Railways, Surface Transport involved.
3.	**PUBLICATION** Schemes to be published in the Official Gazette/local newspapers as the generating company may consider necessary along with a notice for at least two months and modification if any consequent to public representation.	STATE GOVTS.	Section 29 clause (2),(3),(4) and 6 E(S) Act, 1948 State Govts.

Appendix 3.4

Sl. No.	Item	Agency	Remarks
4.	**WATER AVAILABILITY**	1.State Govt.	Interaction between State Govt. Deptts & CWC required
		2.CWC	Relevant Irrigation Act of the State & Central Water Commission
		3.Ministry of Water Resources	For hydel projects only, if inter-state or inter-country
		4.Ground Water Board	For thermal projects only
5.	**SEB CLEARANCE**	1. SEB 2. State Govt.	Sec. 44E(S) Act, 1948.
6.	**POLLUTION CLEARANCE WATER AND AIR**	State/Central Pollution Control Board	Water (Prevention & Control of Pollution) Act, 1974 Air (Prevention & Control of Pollution) Act, 1981.
7.	**FOREST CLEARANCE**	1. State Govt. 2. Min. of E&F	Coordination with State Forest Deptt./Min. of Environment & Forest (MoE&F) regarding Forest (Conservation Act, 1980).
8.	**ENVIRONMENT & FOREST CLEARANCE**	1. State Govt. 2. Min. of E&F	As per item (6) & (7) & Govt. Policy in force.
9.	**CIVIL AVIATION CLEARANCE FOR CHIMNEY HEIGHT**	National Airport Authority	
10.	**REGISTRATION OF COMPANY**	Registrar of Companies	Under Indian Companies Act, 1956.
11.	**REHABILITATION & RESETTLEMENT OF DISPLACED FAMILIES BY LAND ACQUISITION.**	1. Min. of E&F 2. State Govt.	

Sl. No.	Item	Agency	Remarks
12.	HYDRO-PROJECTS (MINI-MICRO)	M/o Water Resources	Under Relevant Acts
13.	EQUIP. PROCUREMENT*	DGTD, CCI&E	Imports & Export Acts
NON-STATUTORY CLEARANCES			
14.	LAND AVAILABILITY	State Govt.	
15.	FUEL LINKAGE	Deptt. of Coal, Deptt of Petroleum & Natural Gas	
16.	FINANCING	CEA, Deptt. of Power, Deptt. of Eco. Affairs, Financial Institutions.	
17.	TRANSPORTATION OF FUEL	Deptt. of Coal, M/o Petroleum & Natural Gas, Ministry of Railways, Shipping & Surface Transport.	
18.	FOREIGN INVESTMENT	Foreign Investment Promotion Board	

[* No longer required under amended policy]

Notes:

1. Captive generation upto 25 MW is exempt from CEA concurrence under Section 28 & 30 of E(S) Act, 1948.
2. Under Section 44, State Electricity Board would refer to CEA for captive generation of capacity exceeding 25 MW.
3. Now, under Section 43, State Electricity Board can purchase surplus power from private generator. The State Electricity Board only needs to consult CEA vide Section 44 (2A). The private generator needs approval of the State Electricity Board only.

Appendix 4.1

KARNATAKA ELECTRICITY BOARD

ELECTRICITY TARIFFS

Tariff Schedule	Nomenclature in brief	Tariff effective from 1.8.199
L.T.1	a) Bhagya Jyothi Kutira Jyothi	a) Rs.250/- per installation per month Note : In addition to the above, the Bhagya Jyothi consumers shall pay the monthly instalments towards recovery of Service main charges as prescribed by the Board from time to time
	b) Domestic and Non-commercial lights and fans	b) Fixed charges Rs.10/- per installation for two months. PLUS Energy charges - 55 paise per unit upto 50 units and 65 paise per unit from 51 units to 100 units 75 paise per unit for the balance units PLUS 7 paise Tax per unit
L.T. 2	a) Domestic power (A.E.H) Non-commercial combined lighting and heating	a) Fixed charges Rs.5/- per K.W. or part thereof sanctioned load subject to a minimum of Rs.20/- per installation per month. Plus Energy charges 105 paise per unit upto 200 units, 160 paise per unit from 201 units to 300 units, 180 paise per unit form 301 units to 400 units, 250 paise per unit for the balance of units PLUS 5 paise tax per unit
	b) Private professional and unaided Educational Institutions	Demand charges - Rs.5/- per K.W. or part thereof sanctioned load subject to a minimum of Rs.20/- per installation per month PLUS Energy charges - 200 paise per unit upto 200 units 250 paise per unit above 200 units upto 400 units, 300 paise per unit for the balance units. PLUS tax at 5 paise per unit.
L.T. 3	a) Commercial Lighting Heating and Motive Power	Fixed charges Rs.12/- per K.W. or part thereof of sanctioned load subject to a minimum of Rs.20/- per installation per month. Energy charges - 350 paise per unit for all the units consumed in the month PLUS 10 paise tax per unit.
L.T.4	Irrigation Pump Sets Lift Irrigation Schemes/Societies a) I.P. Sets	
	i) Upto & inclusive of 10 HP	i) Free power supply subject to clearance of arrears
	ii) Above 10 HP	ii) 50 paise per unit for all the units consumed, subject to minimum of Rs.130/- per H.P. per annum PLUS Tax 5 paise per unit

Tariff Schedule	Nomenclature in brief	Tariff effective from 1.8.1993
	b) Water supply & Sewerage pumping installations	
	i) Village/Town/Mandal Panchayats/interim Mandal Panchayats/Town Municipalities & Organisations run on charitable basis	i) Minimum charges - Nil Energy charges - 65 paise per unit for all the units consumed in the month
	ii) Municipalities/Corporations /State and Central Government/APMC Yard installations	ii) Fixed charges - Nil Energy charges - 85 paise per unit for all the units consumed in the monthly subject to a minimum of Rs.32.50 per K.W. of sanctioned load per month PLUS 5 paise tax per unit
	iii) Water supply installations in Residential Layouts	iii) Minimum charges - Nil Energy charges 125 paise per unit for all the units consumed in the month PLUS Tax of 5 paise per unit
	c) Private Horticultural Nurseries	75 paise per unit for all the units consumed subject to a minimum of Rs.130 /- per H.P. per annum of sanctioned load irrespective of the connected load PLUS Tax 5 paise per unit
L.T. 5	Industrial Non-industrial, Heating & Motive Power including Lighting	Fixed charges Rs.15/- per H.P. per month of sanctioned load PLUS Energy charges 145 paise per unit for all the units consumed in the month. PLUS Tax 10 paise per unit
L.T 6	Street Lights/Public Lighting	
	a) For Villages/Mandal/Interim Mandal/Town Panchayats Town Municipalities	a) Rs.150/- per KW per month of connected load
	b) For other Street Lights	b) Rs.250/- per KW per month of connected load No tax
L.T. 7	Temporary Power Supply	a) Energy charges 400 paise unit consumed or Rs.60/- per KW or part thereof sanctioned load per week whichever is higher. PLUS 10 paise tax per unit
H.T. 1	Public Water Supply & Sewerage Pumping Installations	Demand charges Rs.75/- per KVA per month of billing demand plus Energy charges 130 paise per unit for all the units consumed in the month PLUS 10 paise tax per unit
H.T. 2	a) Industrial Non-industrial and non-commercial	Demand charges - Rs.90/- per KVA per month of Billing Demand PLUS Energy charges - 150 paise per unit upto one Lakh Units, 170 paise per unit for above one lakh and upto two lakh units, 175 paise per unit for balance units PLUS Tax at 10 paise per unit

Tariff Schedule	Nomenclature in brief	Tariff effective from 1.8.1993
	b) Commercial	Demand charges - Rs.100/- per KVA per month of billing demand. PLUS Energy charges - 190 paise per unit upto 1 lakh units, 210 paise per units above one lakh and upto 2 lakh units, 225 paise per unit for balance units. PLUS Tax 10 paise per unit
	c) Industries with C.D. of 50 MVA and above which are 100 % export oriented	Demand charges - Rs.45/- per KVA per month of billing demand. PLUS Energy charges - 150 paise per unit upto 1 lakh units, 160 paise per unit above 1 lakh upto 2 lakh units, 175 paise per unit for balance units PLUS Tax at 10 paise per unit
H.T. 3	Irrigation and Agricultural Farms. Lift irrigation services Lift irrigation schemes and Horticultural Famrs.	Demand charges - Nil PLUS Energy charges - Rs.300/- per H.P. per annum of connected load PLUS Tax 5 paise per unit
H.T. 4	Rural Co-operative Societies	Demand charges - Nil Energy charges - 40 paise per unit for all the units consumed No tax
H.T 5	Temporary Power Supply at 11 KV & above	Demand charges - Rs.165/- per KVA per month contract demand PLUS Energy charges - 350 paise per unit for all the units consumed in the month PLUS Tax at 10 paise per unit
H.T. 6	Railway Traction	Demand charges - Rs.90/- per KVA per month of billing demand. PLUS Energy charges - 200 paise per unit for all the units consumed in the month

Appendix 4.2

Appendix 4.2

TARIF STRUCTURE - K.S.E.B
KERALA STATE ELECTRICITY BOARD

I. EXTRA HIGH TENSION SUPPLY

(a) 66 KV Consumers (Power Intensive/Non-Power Intensive)

	1-10-1994 to 31-3-1995	1-4-1995 to 31-3-1996
Demand charge Rs./KVA of Billing Demand/Month	80	91
plus		
Energy Charge at Ps./Unit (kwh)	82	84

(b) 110 KV Consumers (Power Intensive/Non-Power Intensive)

	1-10-1994 to 31-3-1995	1-4-1995 to 31-3-1996
Demand Charge Rs./KVA of Billing	75	86
plus		
Energy charge at ps/Unit (Kwh)	81	83

II HIGH TENSION SUPPLY

H.T. - I

Applicable to Water Works, Printing Press including presses engaged in printing dailies, Granite Crushing Units, Industrial consumers etc.,

	1-10-1994 to 31-3-1995	1-4-1995 to 31-3-1996
Demand charges Rs./KVA of	85	95

Billing demand/Month

Plus

Energy charges Ps./Unit (Kwh)	83	87

H.T - II

Applicable to consumers such as Hotels, Lodges, Commercial establishments, Business Houses, Film Studios, Cinema Theatres including air conditioned ones etc.,

Demand charges at Rs.85/KVAS of billing demand per month

Plus

Energy charges at Ps.88/Unit (Kwh) for all units consumed

HT - III

Applicable to nonOindustrial non-commercial consumers such as Aerodromes, Radio Stations, Doordarshan, Telephone Exchanges and Public Ofices run by Central/State Government, Local Bodies, Technical & Educational Institutions and Hostels run by or affiliated to Universities or Government Departments and Hospitals and Nursing Homes, Charitable Institutions, Colonies Supplied with energy at H.T etc.,

Demand charges at Rs.85/KVA of billing demand per month

Plus

Energy charges at Ps.86/Unit (Kwh) for all units consumed.

H.T -IV - Agricultural

Applicable to agricultural consumers for all cultivations including dewatering and lift irrigation.

Demand charges at Rs.60/KVA of billing demand per month

Plus

Energy charges at Ps.50/Unit (Kwh) for all units consumed.

III LOW TENSION SUPPLIES

L.T- I.Domestic

Applicable to consumers coming under L.T Supply for domestic use for lights, fans, refrigerators, radios, television receivers, stereos, mixers, grinders, heaters, electric iron, cooking ranges, ovens, sewing machines, pumpsets and such other appliances all in actual domestic use for the occupants of the consumers' premises.

(i) LT-I (A)

All consumers coming under L.T Single Phase supply for domestic use as defined above, whose half yearly consumption is between 0-600 units (average monthly consumption of upto 100 units) and having suitable slabs allotted by the Board and those consumers whose monthly/average monthly consumption is upto 100 units and coming under systems of billing adopted by the Board from time to time, will come under this category.

The tariff rates for slabs from 3 to 8 will be revised as under:

Slab No	Average monthly consumption of slab units (kwh)	Maximum half yearly consumption units (Kwh)	Total flat rate per month (excluding duty etc) (Rs.)
1.	1-15	90	8.55
2.	16-20	120	12.10
3.	21-30	180	18.00
4.	31-40	240	24.00
5.	41-50	300	31.10
6.	51-65	390	41.55
7.	6-80	480	56.10
8.	81-100	600	70.00

ii. LT I (B)

All consumers coming under LT single phase supply for domestic use as defined above, whose average monthly consumption/monthly consumption is above 100 units.

The tariff applicable shall be:

Energy charge at 70 ps/unit upto 100 units
Energy charge at 90 ps/Unit from 101 to 150 Units
Energy charge at 110 ps/Unit from 151 to 200 Units
Energy charge at 160 ps/Unit for units 201 and above

(iii) LT I (C

All consumers coming under LT 3 Phase supply for domestic use as defined above will come under this category.

The tariff applicable will be:

Energy Charges at 70 ps/Unit upto 100 units
Energy charges at 90 Ps/unit for units from 101 to 150 Units
Energy charge at 110 Ps/Unit for units from 151 to 200 Units
Energy charge at 160 Ps/Unit for units from 201 to 300 Units.
Energy charge at 120 Ps/Unit for units 301 and above
Energy charge is subject to a minimum of Rs.70 per month.

LT - II - Colonies Supplied at LT

(i) Colonies of Universities, State/Central Government Departments, Public Institutions like Companies/Board under State/Central Government and Hospitals therein.

Fixed charge Rs.600 per month

plus

Energy charge at Ps.170/Unit

(ii) Colonies of Railways, State/Central Government Undertakings, Postal/Telecommunication Departments, A.I.R., Doordarshan, Private Sector undertakings, Private colonies and others not included in LT II (I)

Fixed charge Rs.600 per month
plus.
Energy Charges at Ps.185/Unit

LT III - Temporary Illumination, Exhibition Festivals and Fairs (Single or Three phase supply)

Energy charge at Ps.360 per unit (Kwh) subject to a daily minimum of Rs.36/Kw or part thereof of connected load.

LT - IV

Supplies for general purpose industrial loads (single and 3 phase) which are purely, resistive and also applicable to general purpose industrial consumers with inductive loads who have installed ISI approved capacitors of recommended value (see Annexure I). The consumers included are generally Grinding Mills, Flour Mills, Oil Mills.

e Factories with or without cold storage, nainly for production and/or repair, pumping purpose including Public Water Works and laundries; Hatcheries, Screen Printing of inting Press, Milk Chilling Plant, Freezing akeries (where manufacturing process and he same premises), Stone Crushing units, Binding and allied activities. Electric nstalled by local bodies, Mushroom farms, nputerised colour photo printing, computer SSI registration and engaged in software *ng activities etc., will come under this tariff.*

	From 1-10-1994 to 31.3.1995	From 1-4-1995 to 31.3.1996
rt er	Rs.15	Rs.15
plus		
	Ps.100	Ps.100

Industrial premises

d power load shall be segregated and meters. The lighting consumption in percent) of the bulk energy consumption be charged at 30 ps (thirty paise) per unit nd above the specified rate. Where e the entire current charges (Fixed charge ill be increased by 50% (fifty percent).

ers eligible for tariff concession in having ustry vide G.O (Rt) No.65/87/PD dated 1- cted load for lighting is less than 20% nnectred load for power, it shall be tapped without segregation. Where the lighting imit, the whole lighting load shall be tered by a sub-meter and lighting of 50% (fifty percent) of athe bulk energy r proper shall be charged at 30 ps (thirty extra over and above the specified rate.

Where segregation is not done the entire current charges (Fixed charge and Energy charge) will be increased by 50% (fifty percent).

In the event of the static capacitor becoming faulty or unserviceable, the consumer shoulf forthwith intimate the matter to the Electrical Section Officer concerned and make immediate arrangements for repair. If the capacitor is not put back into service duly repaired and to the satisfaction of the Board within two months, enhanced charges as per Note 1 shall be payable for the whole period during which the capacitor was faulty.

(e) **LT V- Agriculture**

Applicable to poultry farms, silk worm breeding, Government Livestock Farms, Agricultural consumers, all cultivations including dewatering and Lift Irrigation (Single or 3 phase) who have installed ISI approved capacitors of recommended value (See Annexure I) for their inductive load.

(1) For consumers having connected loads upto 5 KW (Single or 3 phase)

Fixed charge Rs.5 per consumer per month
plus
Energy charge at Ps.12 per unit (kwh)

(2) For consumers having connected loads have 5 KW and upto 10 KW (3 phase)

Fixed charge of Rs.10 per consumer per month

plus

Energy charge at Ps.12 per unit (kwh)

(3) For consumers having connected loads have 10 KW and upto 40 KW (3 phase)

Fixed charge of Rs.3 per kw or part thereof of connected load per month

plus

Energy charge at Ps.12 per unit (kwh)

(4) For consumers having connected loads above 40 KW (3 phase)

Fixed charge at Rs.5 per kw or part thereof of connected load per month

plus

Energy charge at Ps.12 per unit (kwh)

LT VI-Non-domestic (Single or three phase)

LT VI (A). - Temples, Churches, Mosques, monasteries, premises of religious worship, orphanages, convents, private hospitals registered under Travancore-Cochin Cultural. Scientific and Charitable Societies Act and exempted from payment of Income Tax, Government or private educational institutions, libraries/reading rooms affiliated to Universities or run by Government or private (excluding those in the Panchayat area and recognised by the Kerala Grandhasala Sangham), Government Hospitals, X-Ray Units and laboratories attached to Government Hospitals.

Fixed charge : Rs.10 per kw or part thereof of connected load per month

plus

Energy charge per unit : (i) upto 5 kw : Ps.115
(ii) above 5 kw : Ps.155

LT VI (B). - Offices and institutions under State/Central Government Corporations/Board under State/Central Government, Local Bodies, Hostels of educational institutions affiliated to the Universities, or under the control of the Director of Technical/Medical Education, Director of Public Instructions or such other officers of the Government or run by the Government or State Social Service Board, Hostels run by institutions that are registered under Travancore-Cochin Literary Scientific and Charitable Societies Act and exempted from payment of Income Tax, Travellers' Bungalows and Guest/Rest Houses under Government, Typewriting Institutes, private hospitals, private nursing homes, private clinical laboratories/X-Ray units, offices of Advocates and Chartered Accountants.

Fixed charge : Rs.15 per kw or part thereof of connected load per month

plus

Energy charge per unit : (i) upto 5 kw Ps.130
(ii) above 5 kw Ps.170

LT VI (C).- Offices or Institutions under Water Authority, income Tax/Central Excise/Customs or any Government Office engaged in tax/duty/revenue collection other than local bodies, Railways, International/National Airport Authority, A.I.R., Doordarshan, Postal/Telecommunication department. Railway Stations, Radio Stations, TV Stations, LI.C., recognised Insurance Companies, Banks and any other categories not included in LT VI (a), (b) or (d).

Fixed charge Rs.50 per kw or part thereof of connected load per month

plus

Energy charge per unit : (i) upto 5 kw Ps.198
(ii) above 5 kw Ps.248

LT VI (D).- Libraries/Reading rooms recognised by the Kerala Grandhasala Sangham located within Panchayat areas.

Fixed charge Nil

plus

Energy charge per unit (i) upto 100 units kwh : Ps.70
(ii) above 100 units kwh :Ps.90

LT VII-Commercial

LT VII(A).- Display lights, Cinema Studios, Commercial premises, Hotels and restaurants (having connected load exceeding 1500 W), Showrooms, Business Houses, Private Hostels/Lodges/Guest/Rest houses, commercial cold storages, bakeries (without manufacturing processes), vehicle service stations, petrol/diesel bunks, construction works (residential, industrial, non-domestic or commercial).

part thereof per month

plus

Energy charge per unit	(i)	upto 100 units	Rs.150
	(ii)	upto 200 units	Rs.250
	(iii)	above 200 units	Rs.275

LT VII(E).- Sports/Games and/or Arts Clubs having their own buildings, located within Panchayat areas and having a connected load not exceeding 2 KW.

Fixed charge per month : Nil

plus

Energy charge per unit	(i)	upto 100 units	Ps.70
	(ii)	above 100 units	Ps.90

If the connected load exceeds 2 KW, LT VII (C) will be applicable.

LT VIII-Temporary Extension (Single or three phase)

Applicable to temporary extension taken from consumers' premises:

Fixed charge of Rs.16/kw or part thereof of connected load per day.

Appendix 4 3

POWER TARIFF

TAMIL NADU ELECTRICITY BOARD

There was revision of Tariff during the year 1994-95 The tariff rates of High Tension and Low Tension were revised with effect from 1 2 95 (and the revised rates are as per G O. Ms No.29, Energy (A2) dt 31 1 95 The latest revision of Tariff rates are furnished below)

Category	Rate per kVA of maximum demand per month (in Rs.)	Rate per kwhr Madras Metropolitan area	 Non-Metro Politan area
HIGH TENSION			
TARIFF - I			
1 Registered factories, tea estate, textiles, railway tractions, fertilisers, Salem Steel Plant, Heavy Water Plant, Caustic Soda, Calcium Carbide, Aluminium, Potassium Chlorate and all other Industrial Establishment	100	250	240
TARIFF - II			
1 Recognised educational institutions, Hostels run by recognised educational institutions, Government Hospitals, actual places of public worship, orphanages, public libraries, water works, public lighting and such other institutions declared by the Government from time to time	85	200	190
TARIFF III LICENCES			
This Tariff is applicable to the 3 Municipal Licenses at Madurai, Karur and Pollachi			
1 45% on total power consumption	50	100	100
2. Remaining 55% of Power Consumption	50	150	150
TARIFF - IV			
1. Lift Irrigation Co-operative Societies for Agriculture		(in paise) 15	(in paise) 15
TARIFF - V			
1. Supply to Pondicherry State	Thermal Station- I Rate charged by Neyveli Lignite Corporation to the Tamil Nadu Electricity Board plus 10 paise per kWh as wheeling charges plus 4% on the energy wheeled towards Transmission Loss.		
TARIFF - VI			
1. Public Sewage works by Government/ Local Bodies, Laboratories, Research institutes and Studios.	(In Rs.) 90	(In Paise) 220	210
TARIFF - VI - A			
Cinema Theatres	75	150	140
TARIFF - VII			
All categories of consumers not covered under High Tension Tariff I,II,III,IV, V,VI and VI-A	100	270	260

Appendix 4.3

	Categories	Madras Metropolitan areas paise/kWh	Non-Metropolitan areas paise/kWh	Minimum monthly current consumption charges
	LOW TENSION :			
	TARIFF - I			
1	Domestic purposes for lights and fans including radios and power loads Handlooms in residences of Handloom weavers, public conveniences maintained and run by local bodies and by such other organisations as specified by the Govt. From time to time. Community Nutrition Centres and Block Offices of the project, Anganwadi Centres, Nutritious Meals Centres and School Buildings associated with Government Welfare Schemes.	(In paise per kWh)		
(a)	For Consumption upto 25 kWh per month	65	65	
(b)	For consumption from 26 kWh to 50 kWh per month	75	7	Minimum monthly charges Rs. 10/- per service plus fixed charges Rs. 5/- p.m per service for consumption above 50 units per month
(c)	For Consumption from 51 kWh to 100 kWh per month	100	100	
(d)	For Consumption from 101 and 300 kWh per month	150	150	
(e)	For Consumption from above kWh per month	220	220	
	TARIFF - II			
	PUBLIC LIGHTING AND PUBLIC WATER SUPPLY :			
(a)	Village. Town Panchayat and Township Area	(in Paise per kWh) 160	-	Monthly Minimum Rs. 20/- per services
(b)	Municipality and Municipal Corporation Areas	175	-	
	TARIFF - III			
	Cottage and Tiny Industries, power looms. Small Gem Cutting units and Agriculture having a connected load not exceeding 10 H.P.	(in Paise per kWh)		
(a)	For consumption upto 250 kWh per month	120	..	fixed charges Rs. 30/- per service / m
(b)	For consumption above 251 kWh to 750 kWh/m	200	...	Monthly minimum Rs.30/- per service, connected load shall not exceed 10 H.P
(c)	For consumption 751 kWh and above per month	220	...	
	TARIFF - IV			
	Coffee grinding, Ice Factory, Body building Unit, Saw Mill, Rice Mill, Flour Mill, Prawn Farming, Poultry Farming, Battery charging units and Industries not covered under L.T. Tariff - III			
	Power Loads (Industrial non industrial including factory lighting) upto 750 kWh/month	240	230	Fixed charges Rs. 30/- per service/month + Energy
	For consumption above 750 kWh /month	280	270	charges monthly minimum charges Rs. 40/- per k.W. or part thereof of contracted load

Note :

For supply to welding sets, this rate is increased by 25%

Categories	Madras Metropolitan areas paise/kWh	Non-Metropolitan areas paise/kWh	Minimum monthly current consumption charges
TARIFF - V			
AGRICULTURE :			
Farmers	No Charge		a) Agriculturists under self Finance Scheme by payment of actual cost or minimum of Rs. 25,000/- shall be charged at Rs. 150/- per H/P / annum b) Agriculturists under self Finance scheme by payment of Rs. 10,000/- shall be charged at Rs. 250/- per HP/annum or metered tariff at the rate of fifty paise/unit, at the option of the consumer.
TARIFF - VI			
Huts in Village Panchayats, Houses constructed under Jawahar Velai Vaipu Thittam THADCO and Kamarajar Adi Dravidar Housing Scheme and huts in town panchayats in Kanyakumari District alone	No Charge		
TARIFF - VIII			
Recognised education institutions hostels run by recognised educational institutions, hostels run by Adi Dravidar and Tribal Welfare and Backward Class Welfare Department Government Hospitals, actual places of public Libraries, homes for destitute and old people, flood lighting arrangements in the Rock Fort Temple, its environs and the roads and pathways leading to the Temple, of Tiruchirappali and such other institutions declared by the Government	235	225	a. Fixed charges Rs. 10/- per service per month plus Energy Charges. b. Monthly charges Rs. 20/- per service.
TARIFF - VIII			
Laboratories Research Institutes, Studies	240	230	a. Fixed charges Rs. 10/- per service (per month) plus energy charges b. Monthly minimum charges Rs. 20/- per service.
TARIFF - VIII-A			
Cinema Theatres	200	190	a. Fixed Charges Rs. 10/- per/ m b. Monthly Minimum charges Rs. 10/0 per service

Categories	Madras Metropolitan areas paise/kWh	Non-Metropolitan areas paise/kWh	Minimum monthly current consumption charges
TARIFF - IX			
All categories of consumers not covered under Low Tension Tariff I, II, III IV, V, VI, VII VIII and VIII-A			
i. Upto 100 kWh / month	285	275	a. Fixed charges Rs. 10/- per service per month plus Energy charges
ii. Above 100 kWh/month	335	325	b. Monthly Minimum charges Rs. 25/- per service.
TEMPORARY SUPPLY :			
a) Lighting or combined installation of lights and Fans mixed load of lights and power exhibition, motive power heating.	Rs. 4/- per kWh		Minimum Rs. 15/- per kW per day or part thereof
b) Lavish illumination	Rs. 8/- per kWh		Rs. 50/- per kW per day or part thereof.

I	Origin	Destination	Distance (KMS)		
	Mangalore(Imported)	Mangalore	0		
	Talcher (Indigenous)	Mangalore	2922		
	Ib valley	Mangalore	3132		
	Korba	Mangalore	3323		
II	Delivered price for Coal		Imported coal	Domestic coal	
	Pithead cost	Rs/T		264	
	Royalty	Rs/T		50	
	Storing duty	Rs/T		3.5	
	C. Sales tax	%		4	
	C. Sales tax	Rs/T		12.7	
	f.o.b. price	Rs/T		330.2	
	c.i.f. price	Rs/T	1750		
	Import duty @35%	Rs/T	350		
	Total c.i.f.	Rs/T	2100		
	Port charges	Rs/T	225		
	Total price	Rs/T	2325		
	Transportation cost				
	Mangalore(Imported)	Rs/T	0		
	Talcher (Indigenous)	Rs/T		844	
	Ib valley	Rs/T		948	
	Korba	Rs/T		1055	
III	Landed cost				
	Mangalore(Imported)	Rs/T	2325		
	Talcher (Indigenous)	Rs/T		1399.2	
	Ib valley	Rs/T		1503.2	
	Korba	Rs/T		1610.2	
IV	Imputed value related to capital cost	Units	Imported coal based	Indigenous coal based	Natural gas based
	1.Capacity	MW	1	1	1
	2.Capacity utilisation	(%)	68.5	68.5	68.5
	3.Annual output	MWh	6000.6	6000.6	6000.6

	4.Auxiliary consumption	(%)	9.5	9.5	3			
	5.Units sent out/annum	MWh	5430.54	5430.54	5820.58			
	6.Capital cost	Rs.million	40	34.7	24.5			
	7.Phasing of investment							
	Year -3		0.2	0.2	0			
	Year -2		0.3	0.3	0.2			
	Year -1		0.4	0.4	0.5			
	Year -0		0.1	0.1	0.3			
	Total		1	1	1			
	8.Discounted factor		0.12	0.12	0.12			
	9.NPV factor		1.21	1.21	1.11			
	10.NPV of capital cost	Rs.million	48.21	41.82	27.22			
	11.Life of plant	Years	25	25	20			
	12.CRF		0.13	0.13	0.13			
	13.Annutised capital cost	Rs.million	6.15	5.33	3.64			
	14.Capital cost/KWh of power	Rs./KWh	1.13	0.98	0.63			
	15.Calorific value	Kcal/Kg	6250	4200				
	Calorific value	Kcal/Cu.Meter			8760			
	16.Heat rate for coal based plants	Kcal/KWh	2500	2500				
	Heat rate for CC plants	Kcal/KWh			1625	1625		
	17.N.gas consumption/KWh (gross)	NM^3			0.19	0.19		
	18.N.gas consumption/MWh (net)	NM^3			0.18	0.18		
	19.Imputed value related to capital cost	Rs/1000 nm3			1978.21	2811.73		
V	Imputed value related to fixed operating cost							
	1.Fixed operating cost as percentage of capital cost	(%)	2.5	2.5	2.5			
	2. Total fixed operating cost/kwh	Rs. mill	1	0.8675	0.61			
	3. Fixed operating cost (Rs./kwh)	Rs/kwh	0.18	0.16	0.11			
	4.Imputed value related to fixed operating cost	Rs/1000NM3			302.96	438.56		
VI	Sp. consumption of raw materials and utilities							
	Coal(Imported)	T/MWh	0.40					
	Coal(Indigenous)	T/MWh		0.60				
	Fuel oil	T/MWh	0.00	0.00				
	Natural gas per KWh	T/MWh			0.19		Price of fuel oil	5896.00

VII	Cost of raw materials(gross)								
	Mangalore(Imported)	Rs/KWh	0.93		0				
	Talcher (Indigenous)	Rs/KWh		0.83	0				
	Ib valley	Rs/KWh		0.90	0				
	Korba	Rs/KWh		0.96	0				
	Cost of raw materials(net)								
	Mangalore(Imported)	Rs/KWh	0.84						
	Talcher (Indigenous)	Rs/KWh		0.76					
	Ib valley	Rs/KWh		0.81					
	Korba	Rs/KWh		0.87					
VIII	Imputed value of natural gas related to raw materials								
	Mangalore(Imported)	Rs./1000 NM^3	4687.43						
	Talcher (Indigenous)	Rs./1000 NM^3		4198.85					
	Ib valley	Rs./1000 NM^3		4510.20					
	Korba	Rs./1000 NM^3		4830.53					
IX	Total imputed value				Rs/1000 NM3	US$/1000 NM3	US$/Gcal	Gcal/MMBtu	US$/MMBtu
	Mangalore(Imported)	Rs./1000 NM^3			7937.72	226.79	25.95	3.97	6.54
	Talcher (Indigenous)	Rs./1000 NM^3			6480.02	185.14	21.18	3.97	5.34
	Ib valley	Rs./1000 NM^3			6791.37	194.04	22.20	3.97	5.59
	Korba	Rs./1000 NM^3			7111.70	203.19	23.25	3.97	5.86
X	Imputed value of natural gas								
	Mangalore(Imported)	US$/MMBtu	6.54						
	Talcher (Indigenous)	US$/MMBtu		5.34					
	Ib valley	US$/MMBtu		5.59					
	Korba	US$/MMBtu		5.86					
XI	Cost of generation		Rs./KWh	Rs./KWh	US cents/KWh	US cents/KWh			
	Mangalore(Imported)		2.16		6.17				
	Talcher (Indigenous)			1.90		5.42			
	Ib valley			1.95		5.58			
	Korba			2.01		5.75			

Page 3 of 3

I	Origin	Destination	Distance (KMS)		
	Mangalore	Mangalore	0		
II	Delivered Price for Naphtha		Imported	Indigenous	
	Ex-storage price	Rs./T	6784.05	6683	
	State sales tax	Rs./T	0	668.3	
	Central sales tax	Rs./T	0	0	
	Excise duty	Rs./T	0	1002.45	
	Countervailing duty	Rs./T	1017.6075		
	Delivered price	Rs./T	7801.6575	8353.75	
	Transportation cost				
	Mangalore	Rs./T	0.00	0.00	
III	Landed Cost				
	Mangalore	Rs./T	7801.66	8353.75	
IV	Imputed value related to capital cost		Imported Naphtha based	Indigenous Naphtha based	Natural gas based
	1.Capacity	MW	1.00	1.00	1.00
	2.Capacity utilisation	(%)	68.50	68.50	68.50
	3.Annual output	MWh	6000.60	6000.60	6000.60
	4.Auxiliary consumption	(%)	3.00	3.00	3.00
	5.Units sent out/annum	MWh	5820.58	5820.58	5820.58
	6.Capital cost	Rs. million	24.50	24.50	24.50
	7.Phasing of investment				
	Year -2		0.20	0.20	0.20
	Year-1		0.50	0.50	0.50
	Year-0		0.30	0.30	0.30
	Total		1.00	1.00	1.00
	8.Discounted factor		0.12	0.12	0.12
	9.NPV factor		1.11	1.11	1.11
	10.NPV of capital cost	Rs.million	27.22	27.22	27.22
	11.Life of plant	Years	20	20	20
	12.CRF		0.13	0.13	0.13

	13.Annutised capital cost	Rs.million	3.64	3.64	3 64			
	14.Capital cost/KWh of power	Rs /KWh	0 63	0.63	0 63			
	15.Calorific Value	K cal/Cu.Metre			8760 00			
	Calorific Value	K.cal/Kg	10560 00	10560 00				
	16.Heat rate for CC plants	K.cal/KWh	1625 00	1625.00	1625.00			
	17.N.gas consumption/KWh (gross)	N M^3/KWh			0 19			
	18.N.gas consumption/KWh (net)	N M^3/KWh			0.18			
	19.Imputed value related to capital cost	Rs/1000 NM^3			0.00			
V	Imputed value related to fixed operating cost							
	1.Fixed operating cost as percentage of capital cost	(%)	2.50	2.50	2.50			
	2.Total Fixed operating cost	Rs. million	0.61	0.61	0.61			
	3.Fixed operating cost(Rs/KWh)	Rs/KWh	0.11	0.11	0.11			
	4.Imputed value related to fixed operating cost	Rs/1000 NM^3			0.00			
VI	Sp. Consumption of raw materials and utilities							
	1.Naphtha(indigenous)	T/MWh		0.15				
	2.Naphtha(imported)	T/MWh	0.15					
	3.Natural gas per KWh	1000 NM^3/MWh			0.18			
VII	Cost of raw materials(gross)							
	Mangalore	Rs/KWh	1.20	1.29				
	Cost of raw materials(net)							
	Mangalore	Rs/KWh	1.16	1.25				
VIII	Imputed value of NG related to raw materials							
	Mangalore	Rs./1000 NM^3	6471.83	6929.82				
IX	Total Imputed value				US$/1000NM^3	US$/Gcal	Gcal/MMBtu	US$/MMBtu
	Mangalore	Rs./1000 NM^3	6471.83		184.91	21.16	3.97	5.33
				6929.82	197.99	22.65	3.97	5.71
X	Imputed value of natural gas							
	Mangalore	US$/MMBtu	5.33	5.71				
XI	Cost of generation		Rs./KWh	Rs./KWh	US cents/KWh	US cents/KWh		
	Mangalore		1.90	1.98	5.42	5.65		

Appendix 5.1: Survey observations

THE ASSOCIATED CEMENT COMPANY LTD. - VADI CEMENT PLANT

Natural Gas is substitute for Coal in Thermal Power Generation in the Plant Quantity of Energy equivalent 5.0 LTPA.

Cost of Coal - Rs. 1220 / MT.
Cost of HSD - Rs. 7.10 / Lt

MYSORE CEMENTS LTD:

Cement is a continuous process industry and fuel cost forms about 33% of manufacturing cost and also quality of fuel plays a major role in the quality of Cement.

Cost of Coal - Rs.1650 / MT
Cost of Furnace Oil - Rs.5.73 / LT
Cost of HSD - Rs.6.85 / LT
Considerable Natural Gas cost Rs. 6,000/MT (Rs. 3000 per 1000 Nm^3

VASAVADATTA CEMENT :

Balancing equipment and Raw mix design are to be changed to meet the requirement. Plant going for a Thermal Power plant of Capacity of 15.7 Mw Coal based, if NG available There is a chance of shift over.

Price NG should be very less than the existing fuel (Coal).

CHETTINAD CEMENT CORPORATION LTD. :

Price of NG should be equivalent to Coal heating value.

Appendix 5.1

THE INDIA CEMENT LIMITED

Interested in Natural Gas.

Cost of Coal	-	Rs. 1690 / MT Rs. 2703 / MT (Import)
Cost of HSD	-	Rs. 1789/ MT
	-	Rs. 6850/ KL

MALABAR CEMENT LIMITED :

Interested in Natural Gas

Cost of Coal	-	Rs.1598 / MT
Cost of Furnace Oil	-	Rs.7.88 / LT
Cost of HSD	-	Rs.7.88 / LT

RAASI CEMENT LIMITED

Interested in Natural Gas

1 To compare the cost of Natural gas with existing fuels like coal + Lignite.

2 The exact source of supply and gurantedd supply

3 NG has to be stored in full proof vessels, whether shell international will provide

4. Sulphur contain in NG will effect the process, it should be minimum :

Cost of Coal	-	Rs. 1224.47/MT
	-	Rs. 1907.91/MT (Lignite)
Cost of Furnace Oil	-	Rs. 5.28 / LT
Cost of HSD	-	Rs. 6.96 / LT

ANDHRA CEMENTS LIMITED

Not interested in NG.

Cost of Coal - Rs. 1042.05 / MT

Cost of Furnace Oil - Rs. 5.67 / LT

Cost of HSD - Rs. 6.94 / LT

SAGAR CEMENTS LIMITED

NG can be consider if it is economical

¾ of the Coal price is attractive. Lot of investment and loss of production due to stoppage during the change over the system.

Cost of Coal - Rs. 1083 / MT

Cost of HSD - Rs. 7.03 / LT

FERTILISER AND CHEMICALS TRAVANCORE LTD.

Plant personnel knows well about the advantages of NG in fertiliser plant. New PAP plant designed for both Naphtha and NG. Whenever Natural Gas available, ready to use the NG

Cost of Naphtha Rs. 3500 / MT

Cost of Furnace Oil Rs. 5.6 / LT

TUTICORIN ALKOLI CHEMICALS & FERTILIZERS LTD.

As fuel stock NG is not useful, only utilities side in Boilers and heaters NG can be used.

Cost of Coal Rs. 2550 /MT(open Market)

Rs. 1750 / MT

MANGALORE CHEMICAL & FERTILISERS LIMITED.

Natural Gas can be used in both feed stock and fuel for furnaces and heaters. Major modifications in the plant are required to be carried out for usage of Natural Gas. Since, the existing plant is designed to run on Naphtha and furnace oil.

Suitable price of Natural Gas, At international price or as given to other fertiliser plants in India.

Cost of Naphtha - Rs. 4050 / MT (Fertiliser Price)
Cost of Furnace Oil - Rs. 4100 / MT (Fertiliser Price)
Cost of HSD - Rs. 5440 / MT

NAGARUJUNA FERTILISERS & CHEMICALS LTD

Presently this plant using NG as a fuel.

Cost of Natural Gas - Rs. 2.5 / Sm^3

FACT PETRO CHEMICAL DIVISION :

Natural Gas can be used in Utilities.

Attractive Natural Gas prices. - Rs. 5/ kg of gas (Rs.2.5/Sm^3 of gas)
Cost of LPG - Rs. 13,500 / MT
Cost of Furnace Oil - Rs. 6,000 / MT
Cost of LSHS - Rs. 6,250 / MT

TAMILNADU PETROPRODUCTS LIMITED

Interested in Natural Gas

Around 20% lower in price for equivalent heat release (FO 9800 koala/kg) lower sulphur and other impurities in LNG should study.

Cost of LPG	-	Rs.13,000 / MT
Cost of HSD	-	Rs. 7,730 / KL
Cost of Furnace Oil	-	Rs. 5,360 / MT

MANALI PETROCHEMCIALS LTD

Interested in using Natural Gas in Boilers.

A marginal profit of atleast 20% is expected in cost steam generated using CNG against Furnace Oil including transportation.

Cost of Furnace Oil	-	Rs. 5,345 / KL

HINDUSTAN INSECTICIDES LTD:

Interested in using NG as fuel in Boiler. In future, if plant expansion takes places then Natural Gas can be used as a feed stock.

Cost of Furnace Oil	-	Rs.5600 / KL
Cost of HSD	-	Rs.7500 / KL

SPARTEK GROUP LTD.

Natural Gas can be directly used in kiln, as it gives clean gas, which is specific advantages in Ceramic Industry.

Attractive price 1/3 or 40% of current heat input (fuel)

Cost of LPG	-	Rs. 13,500 / MT
Cost of LDO	-	Rs. 6,500 / KL

KERALA CERAMICS LTD

By using NG, furnace efficiency can be improved. Continuity of production and constant temperature can be maintained. By using NG, Firing price will come down.

Cost of Furnace Oil	-	Rs. 6000/ KL

BHARAT HEAVY ELECTRICALS LTD

Interested ion NG based on Economics.

Reliability of supply is more important than a terminal at plant. Price should be less than present, but ion the waste case it will be equal to the present price.

EAGLE FLASK INDUSTRIES LTD.

Natural Gas continous supply is necessary, because furnace run for nearly 3 years. Attractive price 50% of present cost.

Cost of LPG	-	Rs. 13,000 / MT
Cost of FO	-	Rs. 5, 600. KL

THE KERALA MINERALS AND METALS LTD.

The plant collaborators "Kerrmegee Chemical Corporation" Okbhana, USA presently using LNG in both process and boilers.
Natural Gas should reach site minimum vapour pressure of 4 kg/cm^2 ambient.

Cost of F.O.	-	Rs. 5,680 / KL
Cost of HSD	-	Rs. 7,058 / KL
Cost of Coal	-	Rs. 2,210 /KL

BINNY MILLS LTD

Interested in using as a fuel in Thermic fluid heaters and boilers production cost will come down.

Cost of Coal	-	Rs.1,500 / MT
Cost of Furnace Oil	-	Rs.5,680 / KL

BELLARY STEELS & ALLOYS LTD :

The plant going for expansion, Natural Gas is alternative fuel for both blast furnace and sponge Iron Kilns in place of Coal. Natural Gas gives a better degree metalisation in Sponge Iron compared to Coal.

SPIC

Present fertiliser plant designed for Naphtha and Furnace Oil. New plant coming at middle east is Natural Gas based. No. Of LPG connections from SPIC Jyothi PMS Discussed.

Appendix 5.2: Overall observations

Name	Address	Natural gas subsitute
ACC (Wadi Cement Works)	General Manager Wadi Cement Works Wadi, Gulbarga 585 225 Ph: 62235, 62239 Fax: 08474-62190	Coal can be substituted by natural gas. Interested in using natural gas in process & captive thermal power generation
Mysore Cements Ltd.	Mr. N C Panicker Executive Vice President Ammasandra, Tumkur Ph: 78551, 78692 Fax: 08139-8375	Thermal energy sources in Kiln can be substituted by natural gas
Vasavadatta Cement	Mr. P K Goyenka President Sedam, Gulbarga 585 222 Ph: 76006 Fax: 08441-76139	Coal can be substituted by natural gas
Chettinad Cement Corpn. Ltd.	Mr. A P Arasappan Chief General Manager Puliyur, Tamil Nadu 639 114 Ph: 21144, 22744 Fax: 04324-24032	Coal, Lignite, Furnace Oil can be substituted by natural gas
The India Cements Ltd.	Mr. D Sivagurunathan General Manager Chilamkur, Cuddapah 516 310 Ph: 76150, 76154 Fax: 08563-76155	Coal can be substituted by natural gas
Malabar Cements Ltd.	Mr. K. Muralidharan Nair Deputy General Manager (TS) Walayar, Palakkad 678 624 Ph: 0491-862373, 862374 Fax: 0491-862230	Coal can be substituted by natural gas
Raasil Cement Ltd.	Mr. M V Radha Krishna President (Works) Vishnupuram, Wadapalli 508 355 Ph: 08689-3249 Fax: 845725 (0842)	Natural gas substitute for existing fuels like coal & lignite

Appendix 5.2

Name	Address	Natural gas subsitute
Andhra Cements Ltd.	Mr. S V S Shetty Vice President (Operations) Durga Cement Works Dachepalli 522 414 Ph: 57429 Fax: 040-394147	Not interested in natural gas
Sagar Cement Ltd.	Mr. S Veera Reddy Managing Director 8-2-472/B/2, Road No.1 Banjara Hills, Hyderabad 500 034 Fax 040-316573	Coal can be substituted by natural gas
FACT Engg. & Design Organisation (A Div of fertiliser & Chemical)	Mr. K A Pillai Dy. General Manager (Process) & Mr. Sadasivan, SEDO G Sr. Manager (Urea)	In new RAP plant, natural gas can be used. Old ammonia plant with modifications & utilities side natural gas can be used
Tuticorin Alkali Chemicals & Fertilisers Ltd.	Mr. B. Shantharam Shetty Manager (Devp.) 553, Anna Salai, Teynampet, Madras 600 001 Ph: 4345276 Fax: 4348044	Considers in utility side
Mangalore Chemicals & Fertilisers Ltd.	Mr. N V Ramani Dy. General Manager Parambur Manager 575 010 Ph: 407601 to 407608 Fax: 407938	Natural gas can be used in feed stock, furnaces and fired heaters. Naphtha & F.O. can be replaced by natural gas
Nagarjuna Fertilisers & Chemicals Ltd.	Dr. V. Krishna Mohan Group General Manager (Corp. Planning) Nagarjuna Hills Hyderabad 500 082 Ph: 393495 & 317200 Fax: 394788	Presently using natural gas in process and fuel. Natural gas can be used in Expansion and thermal power plant in place of Naphtha.
FACT (Petrochemical Div.)	Mr. N Mahalingam Dy. General Manager (Tech.) Udyogamandal 683 501 Ph: 91-484-532462 Fax: 5390 - Kochi	Natural gas can be used in boilers and fired heaters

Appendix 5.2

Name	Address	Natural gas subsitute
Tamil Nadu Petro Products Ltd	Mr. R Srinivasan General Manager (Works) Manali, Madras 600 068 Ph: 5941350/60/70/80/90	Interested in natural gas at captive power and heaters
Manali Petrochemical Ltd.	Mr. P Seenivasan Sr. Manager (Tech. Service) Manali, Madras - 600 068 Ph: 5941025 & 5941249 Fax: 044-5941199	Natural gas can be used in boilers
Hindustan Insecticides Ltd	Mr. Dosbosco Dy. General Manager Udyogamandal 683 501, Kochi Ph: 0484-541121 Fax: 0484-532464	Natural gas can be used in boilers
Spartek Group Ltd	Mr. Venkateswaran Group Material Manager 52, Chamiers Road Madras 600 028 Ph: 452780	Natural gas can be used in Kilns
The Kerala Ceramics Ltd.	Mr. Devakinandan Manager Kundava, Kerala 691 501 Ph: 0474-522252 Fax: 0471-522248	Natural gas can be used in Kilns
BHEL (EPO Division)	Mr. K S Murthy General Manager I.I.Sc. Post Bangalore - 560 012	Natural gas can be used in Kilns
Eagle Flask Industries Ltd.	Mr. Ram Mohan Rao Manager (Glass Div.) Thiru-Vi-Ka Indu. Estd. Madras - 32 Ph: 2341095	Natural gas can be used in Glass Furnace and Reheating Furnaces
Kerala Minerals and Metals Ltd.	Mr. K Asokan Chief General Manager Chavara, Kerala 691 583 Ph: 0474-203724 Fax: 047593-7101	Natural gas can be used in Process (Roaster) and Boilers

Name	Address	Natural gas subsitute
Dalmia Magnesite Corpn	Mr. S.K. Misra Director Salem - 636 012 Ph: 448787 & 448222 Fax: 0427-447098	Natural gas can be used in Rotary Kiln
Bellary Steels and Alloys Ltd.	Mr. P Sridhar President Anantapur Road Bellary 583 101 Ph: 2796, 2797 Fax: 08392-77113	Natural gas can be used in DRI (Sponge Iron).
Kudremukh Iron Ore Project (Pelletisaton Plant)	Mr. T R R Rao G M (Technical) II Block, Koramangala BANGALORE 34 Ph: 5531461	Natural gas can be used as thermal energy
Binny Mills Ltd	Mr. Vinayakumar Chief Engineer Buckinghum & Carnatic Mills Perbarex, Madras 12 Ph: 6421051	Natural gas can be used as a fuel in thermicfulid heaters & boilers
Southern Petrochemical Inds. Corpn. Ltd	Mr. G Rajasekaran Sr. Manager (Petroleum Div.) 39, Armerian Street, Madras 600 001 Ph: 2350245 Fax: 2352163	Fertiliser plant designed for Naphtha. In Middle East, with NG fertiliser Plant started
Dyna Makowski Power Co.	Mr. Narayan S Director Jahveer Plaza, 3rd Floor 1A, Nungambakam High Road Madras - 600 034 Ph: 8271118/8269115 Fax: 8276621	
Intech Global Resources Inc.	Mr. Mohan T Director 3731, Bruar Park, Suit 400 Houston, Texas 77042, U.S.A. Ph: 713789-5740 Fax: 713789-4672	